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BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF FREDERICK M. BLOOM

On behalf of

Commonwealth Energy Corporation

Docket No. E-01345A-98-0473
Docket No. E-01345A-97-0773
Docket No. RE-00000C-94-0165

JUNE 30, 1999

EXHIBIT
Commonwealth
8
Admitted

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DIRECT TESTIMONY

OF

FREDERICK M. BLOOM

(Docket Nos. E-01345A-98-0473, et al.)

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Frederick Bloom and my business address is 15901 Red Hill Avenue, Suite 100, Tustin, California 92780.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Chairman of the Board and Chief Executive Officer of Commonwealth Energy Corporation ("Commonwealth"). In 1997, I co-founded Commonwealth, which serves about 60,000 residential, small business, commercial and industrial and government customers in California. We are actively pursuing retail electric customers in other states, including Arizona.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I wish to provide my observations and concerns about this Settlement Agreement proposed by Arizona Public Service Company ("APS") and some selected parties. I believe that I have a unique perspective of a competitive electric marketer that is not affiliated with a regulated utility. It is important to address what makes a competitive market for electric deregulation to succeed in Arizona. I will discuss the necessary components of a competitive electric environment in the context of the APS Settlement Agreement. I will then explain why the APS Settlement Agreement is not in the public interest unless certain provisions are changed so as to allow competitors, such as Commonwealth, to compete. Later, I will address specific aspects of the Settlement that I believe should be changed.

Q. WHY DO YOU BELIEVE YOUR PERSPECTIVE OF THIS SETTLEMENT IS UNIQUE?

A. I am familiar with how to create a competitive electric market, particularly in serving residential and small business customers. Many alternative providers are affiliated with a monopoly utility. Those competitive affiliates have obvious concerns about attacking competitive barriers which might be brought to challenge their own regulated monopoly. Another reason why my views might be different is that most utility affiliates are run by former employees of their regulated monopoly. They are not actually outsiders who are trying to open up a new competitive market, nor have they the experience in framing a competitive environment.

II. NECESSARY COMPONENTS OF A COMPETITIVE ELECTRIC MARKET

Q. PLEASE SUMMARIZE WHAT IS NEEDED FOR A COMPETITIVE RETAIL ELECTRIC MARKET IN ARIZONA?

A. All customers of all rate classes must have the ability to choose their electric suppliers if Arizona intends to have electric competition. A visible "generation shopping credit" must be shown on the customers' bills. Consumers must have clear and concise information with an easy process for switching to alternative providers which includes the third-party verification process we proposed. The cost components of the standard offer rates must be transparent so that customers can compare their present costs to the regulated unbundled rates. Only the competitive electric service, such as generation, metering, meter reading, and billing and collection services, should be different when comparing line items between the Standard Offer rates and billings to the competitive service prices. If customers are confused, they won't switch.

Q. EXPLAIN WHAT THE ELECTRIC SERVICE PROVIDER MUST CONSIDER BEFORE ENTERING THE ARIZONA MARKET?

A. Commonwealth needs easy access to potential customers. Entering the Arizona market will require significant investments in personnel, computers, marketing and overhead costs. A new entrant must overcome the name recognition of the local utility distribution company ("UDC"). That requires considerable start-up and ramp-up costs before the new entrant can make a profit. However, with this substantial investment, new jobs are created, it stimulates the local economy, and more economic development will occur with lower electric bills.

III. OVERVIEW OF THE SETTLEMENT

Q. HOW DOES THIS APS SETTLEMENT RELATE TO ELECTRIC COMPETITION IN ARIZONA?

A. APS is one of the two largest utilities in Arizona. What happens with this Settlement will dictate whether or not Commonwealth can compete in Arizona. If the Settlement is approved as written, Commonwealth will have no choice but to stay out of Arizona.

Q. WHAT ARE YOUR GENERAL IMPRESSIONS OF THE APS SETTLEMENT?

A. It is not really a Settlement. It is merely APS's plan to keep out competitors by creating barriers. In fact, no competitor has signed the Settlement Agreement, nor has the large majority of interested parties. If the Settlement is adopted, Commonwealth and I believe no one else will enter the Arizona market to serve most customers, particularly residential and small business and commercial users. The Settlement defeats the purpose of an open competitive environment.

Q. WHAT IS YOUR PRIMARY CONCERN ABOUT THIS APS SETTLEMENT?

A. I have many objections, but on its face the Settlement does not consider or even begin to promote competition for electric services. The Settlement would allow APS to write its own rules to retain monopoly power and keep out competitors.

Q. WON'T RESIDENTIAL CUSTOMERS BENEFIT FROM THE "THREAT" OF COMPETITION?

A. No, you cannot have "competition" without competitors. The Settlement eliminates the potential competitors; therefore, Arizona will not have real competition. Residential customers benefit the <u>least</u>, if at all, from competition if the APS Settlement is approved. RUCO apparently believes residential customers should remain captive in exchange for 1.5% rate decreases over the next five years. Although I support the rate decreases, I believe residential customers would gain more savings by dropping the barriers created by the APS Settlement and the Rules. Another point is missed by Mr. Greg Patterson in his testimony. He falsely claims that a competitive market will be available in the future to create "efficient production, better service and lower prices" for customers who choose not to change suppliers. No company has filed, and I believe none will file, to serve residential customers. With these more stringent barriers in the APS Settlement, the prospect of anyone serving residential customers is less likely if the Settlement is approved.

Q. WHAT BARRIERS TO COMPETITION ARE YOU REFERRING TO?

A. There are many, as Commonwealth outlined in its Comments and Response to the Rules. The lack of affiliate transaction rules is totally unacceptable. When you start with a dominant incumbent utility like APS, not having affiliate transaction rules would be "a death knell" to anyone who tries to compete.

Another barrier to competition is the limited access to residential customers which is controlled by APS. A third barrier is the metering requirement which is only imposed on customers seeking competitive generation, but those same customers are not required to have time-of-use meters if they buy Standard Offer generation from APS. If that information is so important for operating APS's distribution and transmission system, it should be mandatory for the larger load served by APS. Otherwise, it is discriminatory and clearly a barrier to keep competitors out.

Q. DO YOU HAVE OTHER CONCERNS ABOUT THE SETTLING PARTIES WRITING THEIR OWN RULES FOR COMPETITION?

A. Yes. The Agreement says the settling parties may rewrite the terms and conditions of the Settlement in the future, under Section 1.3. Commonwealth and other competitors are left out, as is the entire public and the Commission. This is another reason why I believe the Agreement is not in the public interest.

Q. ARE THERE INSTANCES WHERE APS's SETTLEMENT IS PROMOTING AN UNLEVEL PLAYING FIELD?

A. Yes. APS is participating in the retail electric market in California under its set of rules resulting from AB 1890. APS is an active participant in the Western Power Trading Forum, a group of alternative providers, who are advocating ways to improve competition in California. Although APS has requested California's rules be modified to improve competition, APS has through its Settlement Agreement proposed a set of rules for Arizona which are more utility-friendly than the California rules. This is simply inconsistent with fair play.

Q. PLEASE EXPLAIN THE DIFFERENCES BETWEEN CALIFORNIA AND ARIZONA.

A. California allows for 100% direct access. Arizona's approach, as would be confirmed in this Settlement, restricts customer access with participation percentages and load aggregation limits. California has uniform rules across most of the state. Arizona has different rules in its two largest service areas. California allows for third-party oral verification of switching. Arizona requires a "wet" signature before a customer may change providers. California has strict affiliate transaction rules; whereas Arizona has none. California allows new entrants access to all meters, but Arizona limits access to meters greater than 40 kW. These are some of the differences that make marketing in California much easier than in Arizona.

Q. PLEASE EXPLAIN WHAT YOU HAVE LEARNED FROM YOUR EXPERIENCE IN CALIFORNIA AND HOW ARIZONA MIGHT BENEFIT FROM THAT CALIFORNIA EXPERIENCE.

A. I recommend that Arizona should adopt what has worked well in California and avoid that which has not. First, California has a generation credit but it doesn't really create a competitive retail market. It is tied to the California Power Exchange and there is not enough "head room" for competitors after paying the competitive transition charge ("CTC"). Competitors and consumers don't know the facts, so they merely offer a discount. Arizona should avoid California's experience and make sure there is a transparent generation shopping credit based on the actual costs APS uses in its Standard Offer rates.

Second, California uses the avoided cost approach in setting the metering and billing credits. That means the utility uses the last incremental savings it would experience if someone else would provide that service. It doesn't reflect the average cost to the utility, so that is why the utility uses such low numbers in giving a credit if the customer buys from someone else. APS's tariff appears to be using the same approach for those metering and billing credits.

Third, California requires electric service providers to install meters on commercial and industrial customers, even though they do not have to do so for the customers they sell generation to. This gives the utility lower marketing and operating costs and drives up the costs of their competitors.

Fourth, the utility can disconnect if their customer does not pay. ESP's cannot. The utility has virtually no risk because of their deposits. The ESPs have all the risk because the consumer can continue using power until the agreement termination notice is effective and the deposit doesn't cover that period. Arizona has adopted the same approach as California.

The consensus in the electric industry is that California's regulations seriously inhibit competition in California. Only 130 thousand meters out of 15 million meters have switched in 18 months, and over 100 thousand switched because of "green power." Over 300 registered to sell competitive services in California, and now less than 10 remain. That is proof that the California approach has not worked. Of those, only one is not a utility affiliate – that is Commonwealth.

Q. HOW HAS COMMONWEALTH BEEN ABLE TO COMPETE IN CALIFORNIA UNDER THESE RESTRICTIONS?

A. Commonwealth can only compete in California because of its "green power" program. It has a pool of funds, similar to Arizona's system benefit charge, which is used to credit customers with 1.5 cents per kWh if they select "green power." This creates an "artificial" market with these rebates being used to subsidize the limited transition to competitive electric services. No company in California would be selling to small customers without the "green program." Arizona does not have a "green program" and I'm not suggesting that it should have one. But with the market barriers similar to California and no "green program," I cannot foresee anyone entering the Arizona electric market to service residential and small business and commercial customers.

Q. WHICH STATE WOULD YOU RECOMMEND AS HAVING THE BEST ELECTRIC COMPETITIVE MODEL?

A. Pennsylvania has the best approach that I know of. It has a well-defined and fixed generation shopping credit. For example, PECO has a 5.65 cents per kilowatt per hour shopping credit with 5.15 cents for generation and a half cent for transmission. That generation shopping credit is based on the actual costs of generation to the utility. The utility's costs are unbundled from the generation costs, and what is left over is the generation shopping credit. Pennsylvania allows for ease of switching through third-party verification. Pennsylvania has no metering requirement; it is optional with the customer. As a consequence, over 500 thousand meters have switched to competitive services, out of 5 million, during the first 6 months. Pennsylvania has shown that electric competition can work if there is a clear price signal, ease of transaction, and a willingness to drop market barriers.

Q. WILL RESIDENTIAL AND SMALL CUSTOMERS BE AFFORDED AN OPPORTUNITY TO SAVE MONEY UNDER THE AGREEMENT?

A. It is difficult to tell, but it is highly unlikely that residential and small customers will save money under the Settlement. I have at least three reasons: the difference between the Palo Verde wholesale generation cost and Commonwealth's retail market price might be too slim if any, the time and cost of calculating any savings will likely be too high, and without a generation shopping credit, customers will be confused or persuaded by APS or its affiliate that Commonwealth as a new entrant doesn't understand how those costs are calculated.

I have reviewed the Palo Verde firm and non-firm prices for 1998 because that is the price that will likely set the Arizona wholesale price. On the surface, I must add to that PV generation cost the transmission costs (and losses), the independent system operator (or independent system administrator) charge, and APS's direct access tariffs. Then I need to compare those costs to APS's existing rates and analyze those differences to see if I can cover marketing costs and overhead and start-up costs and still earn a profit. For example, if PV generation is 3 cents per kWh, transmission is one-half cents, the ISO charge is another one-half cents, Commonwealth's cost is 4 cents <u>before</u> considering the marketing and overhead costs. If default customers who don't switch are being charged 3 cents for generation, Commonwealth cannot compete.

For each customer, Commonwealth will have to conduct a rate comparison and that will add additional costs to the transaction. Commonwealth must overcome this while APS has all the information and presence in the Arizona market.

With all this confusion as to how the potential savings might be calculated, APS will have the upper hand in telling its customers not to switch. At the same time Commonwealth must compete with APS's affiliate, who may have former employees from APS who understand the nuances of APS's tariffs.

IV. THE SETTLEMENT IS NOT IN THE PUBLIC INTEREST

Q. THE PARTIES CLAIM THE SETTLEMENT IS IN THE PUBLIC INTEREST. WHAT IS YOUR OPINION?

A. The Settlement is not in the public interest, the only interest being protected is that of APS and perhaps the other signatory parties. They claim that the rate reductions are in the public interest. Perhaps they are, but we don't know if those reductions are enough or properly allocated. We need a cost-of-service rate study that is current before anyone can say these rate reductions are in the public interest. That study must allocate those costs among the Standard Offer elements as listed in the Rules, particularly A.A.C. R 14-2-1606.C.2. Any utility would be glad to give a 1.5% rate reduction if it should actually be 3% or more. This is all the more important because this limited rate reduction would last for the next 5 years.

Q. ARE THERE OTHER REASONS WHY YOU BELIEVE THIS AGREEMENT IS NOT IN THE PUBLIC INTEREST?

A. Yes, several. The settling parties claim that this Agreement will move Arizona to retail competition faster and so the Commission should approve it as being in the public interest. This is clearly false. This Agreement will delay competition, because it limits choice for residential and small customers and creates barriers to competition. Only APS and its competitive affiliate (APS Energy Services) will be able to move faster towards competition in Arizona and other states.

Q. THE SETTLING PARTIES CLAIM THAT ECONOMIC DEVELOPMENT AND THE ENVIRONMENT WILL BENEFIT FROM THIS SETTLEMENT. WHAT IS YOUR OBSERVATION?

A. The settling parties claim the Agreement is in the public interest because economic development and the environment will benefit from guaranteed rate reductions and the continuation of renewable and energy efficiency programs. These sound like arguments for continuation of the APS monopoly and not for competitive electric markets. Those rate reductions should be ordered if APS is collecting more than its cost-of-service - - even outside of this settlement proceeding. In reality, economic development will be stifled by not giving small and medium business customers competitively priced services just like their bigger competitors. As far as renewable and energy efficiency programs, Commonwealth is a leading proponent of "green" power which it markets competitively in California. APS claims that it is in the public interest to collect its cost of renewable and energy efficiency program through the system benefit charges which are paid by all customers. This is a subsidy to the APS monopoly so it can compete against Commonwealth. Those services should be sold competitively and not be used as an argument as being in the public interest.

Q. DO YOU HAVE OTHER REASONS FOR BELIEVING THAT THIS SETTLEMENT IS NOT IN THE PUBLIC INTEREST?

A. Yes. Universal service coverage for low-income assistance programs and the provider of last resort "obligation" are used by APS and the settling parties to claim that this Agreement is in the public interest. These low-income programs should be maintained but should not be the basis for keeping out competitors. In fact, those low-income programs should be transferable to any ESP who serves those customers. As far as the provider of last resort, those services should be opened up to competition. It is ironic that APS raises the barriers in keeping out competitors and then on the other hand it claims that no one wants to serve customers and therefore it should be the provider of last resort and the Agreement is in the public interest. Robust competition is in the public interest as pronounced by the Arizona Legislature and the Commission. The Settlement does not promote competition and therefore it is not in the public interest.

Q. IS IT IN THE PUBLIC INTEREST TO RESOLVE LITIGATION RELATING TO THE ELECTRIC COMPETITION RULES?

A. Of course, but any party can and perhaps will appeal this Settlement and maybe the Rules. The only interest being served are those of APS and perhaps the other settling parties, because they could go about their business under the Settlement while litigation continues and competitors and residential and small business customers are denied the benefits of competition. Because the Settlement is unfair, and I believe not in the public interest, litigation may be the only recourse short of leaving Arizona's electric market to its incumbent monopoly utilities.

Q. THE SETTLING PARTIES CLAIM IT IS IN THE PUBLIC INTEREST FOR APS TO RECOVER ITS REGULATORY ASSETS AND STRANDED COSTS WITHOUT A GENERAL RATE PROCEEDING. WHAT IS YOUR IMPRESSION OF THAT CONCLUSION?

A. It is incomprehensible to understand how it is in the public interest to order the payment of money by APS' captive customers <u>without</u> a rate proceeding and review of the numbers. APS should be required to file its cost-if-service, others should be able to analyze those numbers, and an open hearing should be held. Only after this unbundling of transmission, distribution and generation costs can the public and Commission know if these regulatory assets and stranded <u>generation</u> cost are valid. Anything short of this process is not in the public interest.

Q. THE AGREEMENT CALLS FOR OPENING RETAIL ACCESS ON JULY 1, 1999 IN THE APS SERVICE AREA. IS THIS A VALID REASON FOR APPROVING THE AGREEMENT?

A. No. This July 1 date will be passed even before the hearing is held. It is clearly an attempt to create the illusion of competition and urgency. As discussed before, no one is prepared to compete under the Rules as written or this Settlement Agreement, except for APS's competitive affiliate because it gains an unfair-advantage under the Settlement Rules.

V. PHASE IN PROCESS AND BARRIERS TO COMPETITION FOR RESIDENTIAL AND SMALL CUSTOMERS

Q. THE SETTLEMENT REFERS TO THE PHASE-IN PROCESS FOR ALLOWING RESIDENTIAL CUSTOMERS TO SIGN UP. WHAT IS YOUR OPINION ABOUT THIS PROCESS?

A. Limiting residential customer access discriminates against that particular class of electric user. They have the most to lose of all customers, if this Settlement is approved. APS claims that is has over 680,000 residential customers and it would allow only 34,000 of them to sign up on a first-come, first-serve basis. APS should not have the ability to control customer choice or dictate how competitors might market and provide savings to those customers. As we learned in California, switching by residential customers is a gradual process. Nevertheless, customers and competitors should not have to be concerned about some arbitrary quarter limit controlled by the utility. Furthermore, the Rules say a <u>minimum</u> 5% of residential customers must receive competitive electric service by October 1, 1999. I believe it won't be possible to meet that objective. But if more residential customers want to save on their electric bills, they should be allowed to switch without resorting to artificial limits. Commonwealth would like to help the Commission meet its goal in making electric competition available to residential customers.

Q. WHY IS CUSTOMER ACCESS SO IMPORTANT TO COMMONWEALTH?

A. Limiting customer change out will make our advertising dollars less efficient. Restricting the customers who may purchase competitive electricity raises Commonwealth's transaction costs. Those higher costs in obtaining customers creates a barrier to entry.

Q. HOW WOULD YOU PROPOSE TO SERVE THESE RESIDENTIAL CUSTOMERS?

A. Commonwealth has extensive experience in consumer marketing and the personnel and computer technology in which to handle the switching to meet these minimum requirements. As we discussed in our Comments and Responses to the Rules, a third-party oral verification process should be implemented so that customers who wish to switch may easily do so. At the same time, this verification process protects against slamming. I strongly urge the Commission to adopt the changes we recommended.

Q. DOES THE APS RESIDENTIAL PHASE-IN PROGRAM CONFLICT WITH THE RULES?

A. Yes. APS' plan creates a <u>maximum</u> of 8,750 residential customers during any quarter. The Rules provide for a <u>minimum</u>. The APS plan also uses the old percentage of 1¼% per quarter which was changed under the present Rules which has an increasing minimum percentage which shows 5% by October 1, 1999. This further illustrates how APS discriminates against the small user and why the Settlement is not in the public interest.

Q. IF THE RULES CONFLICT WITH THE SETTLEMENT AGREEMENT, WON'T THE RULES CONTROL?

A. Normally yes. In my business experience, private agreements must comply with state law. Here the settling parties are asking the Commission to make the Settlement Agreement control over the Commission's Electric Competition Rules. This is clearly against the public interest. APS should not be able to force the Commission to give up its rule-making and rate-making powers and then let APS write its own rules on how its customers and competitors may participate in the electric competition market. Although I'm not a lawyer, this smacks of an anti-trust violation. Again, the Settlement says APS and the settling parties do not even have to comply with Arizona's anti-trust law if its approved by the Commission. This is an unbelievable request by these settling parties.

VI. UNBUNDLED COSTS MUST BE BASED ON APS's PRESENT COST OF SERVICE

Q. THE AGREEMENT CALLS FOR THE STANDARD OFFER BILLS TO BE UNBUNDLED TO THE EXTENT REQUIRED BY THE RULES. IS THIS ADEQUATE FOR PROMOTING COMPETITION AND PROTECTING THE PUBLIC INTEREST?

A. No, for several reasons. First, the Arizona Electric Competition Rules require that the Standard Offer tariff be disaggregated into (a) electricity, with the sub-components of (i) generation, (ii) competition transition charge (CTC), and (iii) must-run generation charge, (b) delivery, with the subclasses of (i) distribution, (ii) transmission, and (iii) ancillary services, and (c) other, which includes (i) metering services, (ii) meter reading service, and (iii) billing and collection, and (d) system benefits. A.A.C. R14-2-1606.C.2. APS asks the Commission to waive this requirement in Section 2.1 of the Agreement.

Second, the public is left out of the process of determining how APS intends to unbundle those costs, which will be paid by both the Standard Offer customers and those that buy competitive services. This ratemaking and all consumers and competitors are entitled to review and challenge how APS makes those allocations.

Third, APS would have the incentive to push many of those costs over to the distribution charge so that customers and competitors would have little or no "head-room" for generation savings and sales. APS already claims that its charges for Standard Offer customers will not be the same as it intends to charge customers who seek competitive services. This is unacceptable, and clearly indicates an anticompetitive and discriminatory rate is intended to be imposed on customers seeking alternative providers.

Fourth, this cost-of-service study must be completed before the Commission approves APS's allocation and interested parties should have an opportunity to review and challenge those numbers and how they are allocated. This is particularly important because the standard offer unbundled tariff will determine the "generation shopping credit" available to those customers who seek competitive generation.

Fifth, APS intends to unveil its "imputed" generation shopping credit only after this Agreement has been approved. If that credit is small or insignificant, it cannot be challenged even if APS has been paying more for its generation than is reflected in the Standard Offer bill and to be used as the generation shopping credit.

Q. HAS APS INCLUDED ITS STANDARD OFFER UNBUNDLED BILL COMPONENTS WITH THIS SETTLEMENT?

A. No, APS has not provided any illustration of its billing components for its Standard Offer or for that matter, for those customers who decide to purchase competitive services. We have no idea what those cost components might be in APS's proposed billing format, including any generation shopping credit.

Q. WHY SHOULD APS UNBUNDLE ITS COSTS SO AS TO SHOW A GENERATION SHOPPING CREDIT?

A. The generation shopping credit is the only way in which customers will know if they have the opportunity to save on their power bills and whether or not competitors can compete. APS said in its Consumer Guide to Deregulation that the "market generation credit" will be separated and shown on their power bills. Obviously, a breakdown of each of those cost components, as itemized in the billing format under the Rules, is needed so that all APS customers and competitors can be sure that APS is not overcharging under its regulated rates and that there is no cost shifting. If there is no shopping credit, customers will be confused and misinformation will likely occur as to how much savings customers will actually be receiving. If there is confusion, customers won't switch and there won't be any competition in Arizona.

Q. WHAT SHOULD BE INCLUDED IN THE GENERATION SHOPPING CREDIT?

A. The generation shopping credit should be based on the full cost of APS's generation costs to its Standard Offer customers. It should include such items as APS's full cost of energy, capacity, ancillary services, Must-Run Generating Units, relevant taxes, reserves, transmission service (or the applicable independent system administrator or independent systems operator), marketing, and administrative and general costs, and the applicable rate of return. If any of these costs are left out of the shopping credit, customers who buy competitive generation will be paying both APS and the alternative provider for those same services. Furthermore, it subsidizes APS' generation costs and limits or prohibits potential competitors like Commonwealth from entering the market and attempting to make a small profit.

Q. WHAT OTHER CONCERNS DO YOU HAVE REGARDING APS's LACK OF UNBUNDLED NUMBERS?

A. General and administrative ("G&A") costs of utilities are significant. Without a cost-of-service study that shows how those costs are allocated, some G&A costs associated with generation might be shifted to the distribution charge. APS has created its competitive affiliate, APS Energy Services, and some of those G&A costs should be reduced because a part of the marketing and business development personnel, overhead and other costs have been transferred over to its affiliate. APS retains the unsupervised flexibility of moving those charges around within the company and between it and APS Energy Services. For example, if its competitive sales does not go as planned, it might shift some of those people back to APS or expand its Standard Offer discount marketing efforts. This is not acceptable, and only a cost-of-service study underpinning the tariffs will prohibit these potential abuses.

Q. WOULD A COST-OF-SERVICE ANALYSIS DELAY COMPETITION?

A. No, but APS uses that argument so that it can get another five years (until July 1, 2004) under its current rate structure. Given the changes in APS and the electric market in general, those costs may be significantly different than in the present rates for APS. Furthermore, filing of the cost-of-service for those regulated services should be readily available from APS management. It would be imprudent for APS to negotiate this Settlement without having those cost figures. The process could be expedited, and continually monitored to be sure that there is no cost-shifting among APS's functions (e.g. transmission, distribution and generation) or between APS's regulated services and its competitive affiliate.

Q. SHOULD CUSTOMERS WITH MORE THAN THREE MEGAWATT USAGE BE REQUIRED TO GIVE APS ONE-YEAR ADVANCE NOTICE BEFORE RETURNING TO THE STANDARD OFFER SERVICE?

A. No. This further illustrates the continued monopoly generation aspects of this Settlement Agreement. Generation is to be opened to the competitive market. This Section 2.3 exposes the illusion of this artificial transition to a completely competitive generation market. By relying on the Standard Offer for big customers, the Settlement really does not foster a full transition to market-valued generation. The settling customers are merely getting a regulated tariff break and will likely pursue a special discount from the APS or buy generation from APS's affiliate. In addition, this Section 2.3 refers to "a direct access supplier" and not to an Electric Service Provider, which implies that all large customers of more than 3 megawatts may purchase from non-ESPs. All alternative suppliers should play by the same rules.

Q. SHOULD APS BE ALLOWED TO CHANGE RATES SCHEDULES OR SERVICE TERMS AND CONDITIONS?

A. No, because APS could unilaterally request a rate or term change that drive up costs to keep competitors out. In Section 2.5 of the Agreement, APS would retain the flexibility of using excess revenues to make special deals or engage in anti-competitive transactions, or impose new terms and conditions on alternative suppliers. APS claims this Settlement avoids a rate proceeding. But APS retains the hammer on customers and competitors in that they must continue to monitor and challenge changes proposed by APS. Consumers and competitors should have the same right to request changes to rate schedules and service terms and conditions so that APS charges its true costs in providing regulated services. This one-sided provision is anticompetitive and against the public interest. As I said before, a rate proceeding is a must which unbundles APS's functions and before APS charges its monopoly tariffs to all customers.

Q. SHOULD APS BE ALLOWED TO PASS ITS COST OF COMPETING TO ALL OF ITS CUSTOMERS?

A. Absolutely not. APS is asking the Commission to allow it to accrue and recover electric competition costs from all of its customers, starting on July 1, 2004. Under this Section 2.6(3), both the standard offer customer and those that purchase competitive service would be subsidizing APS so that it can compete at a lower cost. This is a proposed break for the APS shareholders and it reduces customer savings and potential profit margin for competitors. This is a form of a never ending CTC which would allow APS to create another profit center while recovering "a reasonable return" on those deferred costs. The Commission should not allow recovery of any APS costs relating to its transition to competition.

VII. STRANDED COSTS SHOULD BE DETERMINED ONLY AFTER APS UNBUNDLES ITS RATES

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF STRANDED COSTS.

A. Under the Arizona Corporation Commission Rules (A.A.C. R14-2-1601.35), it is my understanding that stranded cost is defined as the "verifiable net difference" between the "net original cost" of generation assets and the market value of those assets "directly attributable to the introduction of competition" under the Rules. In addition to generation, stranded costs might include regulatory assets, fuel contracts and purchased power contracts, as I read the Rules. I believe that there can be no stranded cost until customers actually leave the APS generation supply. With all the barriers and anticompetitive conditions in the Rules and

Settlement, I don't see how APS could claim it now or will in the future have any stranded cost.

Q. DOES THE SETTLEMENT INCLUDE THE VERIFIABLE NET DIFFERENCE BETWEEN THOSE GENERATION COSTS AND THEIR MARKET VALUES?

A. No, the Settlement does not list the generation plants' net original costs, nor their market values. It appears APS and a selected group of the parties merely negotiated a number. Those figures must be analyzed in the appropriate stranded cost proceeding as previously proposed.

Q. SHOULD APS BE GIVEN A REASONABLE OPPORTUNITY TO RECOVER ITS UNMITIGATED AND LEGITIMATE STRANDED COSTS?

A. Yes, but first the barrier to entry must be dropped and alternative providers must be given a fair opportunity to compete. Second, there must be a stranded cost proceeding to actually assess the reasonableness or legitimate nature of the stranded costs claimed by APS in the Settlement. Those costs cannot be determined until APS unbundles its rates. It would not be in the public interest for APS to negotiate a speculative stranded cost figure with a few of the other parties, particularly when all customers will be affected and the CTC might squeeze competitors out.

Q. SHOULD THE CTC BE FOR A LIMITED PERIOD?

A. Definitely. This Agreement allows for the collection of the competition transition charge through December 31, 2004. Any amount less than $350 million net present value that is unrecovered would be rolled over into a rate increase on July 1, 2004. The Agreement allows for two CTC charges to be collected for the last 6 months of the year 2004 and then the rate increase would continue for an unlimited time. The Agreement does not mention how customers who actually pay the overage or underage would receive the credit or surcharge during that extended CTC period.

Q. DO YOU SEE OTHER PROBLEMS WITH THIS CARRIER-OVER CTC ARRANGEMENT?

A. Yes, APS customers give an interest-free loan to APS if it over collects the CTC before December 31, 2004, but if APS under collects then APS gets a reasonable return. APS assumes no risk and it has no incentive to mitigate its stranded costs. This stranded cost recovery mechanism is not in the public interest.

Q. WHAT OTHER PROBLEMS DO YOU SEE WITH THE STRANDED COST PROVISION UNDER ARTICLE III OF THE AGREEMENT?

A. APS might be able to sell some or all of its generation above its book value or even the net original cost basis that is in the Rules. Consequently, most of the generation that APS claims might be potentially stranded will not occur. As a result, the $350 million net present value of stranded costs appear to be very high and perhaps it should be negative - - in which case, APS should give customers a distribution credit.

Q. HOW WILL THE CTC AFFECT COMPETITION?

A. A higher CTC means there is less "head-room" for generation shopping credits. In other words, customers save less, shareholders gain more, and competitors earn less or no profit.

Q. SHOULD THE CTC INCLUDE THE REGULATORY ASSET CHARGE?

A. Of course, regulatory assets is one component of a stranded cost as I read the Electric Competition Rules. That has been the consistent position of the utilities in the past. Apparently, APS is trying to hide the higher CTC by shifting the regulatory asset charge into the distribution charge. In essence, APS is raising the distribution charge so that it will not have to revisit the legitimacy of these regulatory assets, because the distribution charge will continue until there is a cost-of-service rate case. Customers should know what they are paying for and why. To hide the regulatory assets within the distribution charge is against the public interest.

Q. DO YOU HAVE OTHER PROBLEMS WITH INCLUDING THE REGULATORY ASSET CHARGE WITHIN THE DISTRIBUTION CHARGE?

A. Absolutely. The APS regulatory assets include coal mining reclamation costs and the financing of generation, according to APS's testimony. These are generation costs which are subject to competition. This gives APS an anti-competitive advantage in marketing its generation because all APS customers, including those that might purchase from Commonwealth must pay for APS's generation cost. This is the type of cost-shifting Commonwealth fears. This cross-subsidy is clearly anti-competitive. APS is increasing its distribution charge so as to lower its generation costs so as to keep out competitors and charge higher distribution charges to all Arizona customers. These regulatory assets must be closely examined and the public should be assured that they are legitimate and if so, they should be included in the CTC.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE STRANDED COST PROVISION IN THE AGREEMENT?

A. Yes. Section 3.5 says that the Commission's approval would mean an "irrevocable promise" for recovery of APS's regulatory assets and stranded costs which would survive the expiration of the Agreement and bind future commissions. As I mentioned before, APS wants to write its own competition rules. This appears to me as a laymen to be an unlawful delegation of the Commission's authority to APS and an illegal restriction on the decision making powers of future Commissioners. It is also not clear why the "irrevocable promise" must extend beyond this Agreement or how it might relate to future stranded costs or regulatory assets that might be claimed by APS. This also conflicts with the Commission's position in this proceeding and the U.S. West Communication case, in which the Commission argued successfully that there is no regulatory contract. Approval of this Settlement would establish a new precedent with far reaching implications on claims by other electric utilities and public service corporations regulated by the Commission.

VIII. AFFILIATE TRANSACTION RULES MUST BE IN PLACE

Q. YOU EXPRESSED CONCERNS ABOUT THE LACK OF AFFILIATE TRANSACTION RULES. PLEASE EXPLAIN.

A. The Agreement would allow APS to form any affiliate and the Commission would be required to approve that arrangement. APS could transfer any "competitive service assets" to its affiliate at book value. I strongly oppose the use of book value. A market-based value must be used and those assets should be sold at auction or appraised value. If any generation asset is not sold, the market price for the sold generation could be used in setting the value for unsold generation assets, such as APS's interest in the Palo Verde Nuclear plants. Any net proceeds above book value should go to pay down the stranded cost. The way APS has structured this Agreement, its shareholders would get that benefit and the customers would be saddled with a higher than otherwise CTC charge. Under the Settlement, APS's shareholders would receive all the profit if it decides to sell some of its generation. All customers would still have to pay the high CTC.

Q. DO YOU HAVE OTHER CONCERNS ABOUT THIS CORPORATE STRUCTURE PROVISION UNDER ARTICLE IV IN THE AGREEMENT?

A. Yes, it would grant APS an additional 2 years in which to separate its competitive assets from the regulated services. What this means is that APS would have until 2003 in which to cross-subsidize its competitive services. This delay gives APS the option to solicit customers for its competitive affiliate or make special discount deals to retain them under APS's standard offer. Depending on where the customer goes, APS can decide how to transfer its assets. This seems anticompetitive because no other competitor has this option.

Q. WHAT IS YOUR SOLUTION TO THIS CORPORATE STRUCTURE ISSUE?

A. First, APS should not engage in any competitive services until it has functionally separated its competitive services from the regulated function and until rigid affiliate rules are in place. As a future competitor, I will be buying "wire" distribution services from APS as well as perhaps other regulated services. I need to be assured that there is a "brick and mortar" separation between personnel facilities, information and payments I make to APS as a regulated provider, as compared to APS as my competitor through its affiliate. Only a fool would deal with a monopoly which controls a majority of my costs and has a competitive affiliate that could destroy my business without recourse. The affiliate transaction rules must be reinstated so that we all know what is lawfully permissible.

Q. ARE YOU SAYING THAT FUTURE CODE OF CONDUCT TO BE PROPOSED BY APS IS INADEQUATE?

A. Absolutely. It isn't worth the paper that it will eventually be written on by APS. If the affiliate transaction rules are not reinstated, the Commission will in essence be asking the "fox to guard the hen house." APS would never claim it violated its code of conduct. No one would know if that code was complied with. Competitors and the Commission don't have the resources to "play word games" over how the APS-drafted code is to be interpreted or enforced.

Q. WHAT IS YOUR IMPRESSION OF APS PURCHASING ELECTRICITY FROM ITS EXEMPT WHOLESALE GENERATOR AFFILIATE AT "MARKET BASED" RATES?

A. Amazement and disbelief come to mind. This illustrates the far reaches of this Agreement. APS claims that it should be able to shift its generation assets over to a paper affiliate at book value and buy that generation for its standard offer customers (or special discount customers) or sell it to its competitive affiliate. APS claims this will not violate Arizona's anti-trust law, not be an unfair competitive advantage, and be in the public interest. I disagree with all of those conclusions. Why bother with this bogus arrangement, because it only drives up the CTC charge which all customers would have to pay for APS's lawyers in preparing that paperwork. This Section 4.4 illustrates why the Commission should order divestiture of competitive electric service assets because the monopoly-oriented APS does not understand how market-based rates are determined through open competition.

IX. APS IS GRANTED COMPETITIVE ADVANTAGES

Q. WHAT COMPETITIVE ADVANTAGES ARE GIVEN APS UNDER THE AGREEMENT?

A. APS starts out with name recognition in its service area. It can offer discounts or sell competitive generation through an affiliate in its service area, customers won't really know if they are buying from APS or its affiliate. Only APS will know how the costs are being shifted to grant those discounts. Residential customers will likely bear higher costs if APS gives special deals to preferred customers. APS could give a standard offer discount to a customer in its service area and then sell generation through its competitive affiliate to that customer's business which are in the Salt River Project's or Tucson Electric Power Company's service area.

Q. ARE THERE OTHER COMPETITIVE ADVANTAGES APS WILL RECEIVE UNDER THE AGREEMENT?

A. Yes, APS's control of all its generation through an affiliate gives it market power. APS is a major provider of generation in Arizona. It could sell that power to its standard offer customers, to its competitive affiliate, to retail customers in areas outside of its service area, to retail customers in California, to competitors, and in the wholesale market. Other competitors, such as Commonwealth, would likely purchase some power from APS. By controlling such a large percentage of generation in Arizona, APS could control the price of competitive generation.

Q. HOW CAN APS GAIN A COMPETITIVE ADVANTAGE BY BEING THE PROVIDER OF LAST RESORT?

A. APS splits the process by setting the competitive transition charge ("CTC") in the Agreement, but yet the Settlement allows them to market their excess generation subsidized by the CTC to customers Commonwealth wishes to serve. APS's competitive affiliate is guaranteed a profit. APS can go back for a rate increase if it cannot sell all of its generation. APS recovers all of its costs relating to electric competition under Article II of the Agreement. APS incurs no risk in entering the competitive market. To resolve this, all ESPs should be able to sell generation to Standard Offer customers and APS should not be able to raise any rate during the transition to full competition. If APS was required to auction its "provider of last resort" asset, it is conceivable that income would more than offset the stranded costs it is claiming.

Q. DOES APS HAVE A COMPETITIVE ADVANTAGE WITH RESPECT TO DEPOSITS AND TERMINATING ELECTRIC SERVICE?

A. Definitely. APS starts out with inside information on the credit history of a customer. If that customer is a credit risk, it will keep that customer under its standard offer. If it is a credit-worthy customer, it will pursue that customer through its competitive affiliate. Under the Electric Competition Rules, the deposit is not large enough to pay the electric bills if the customer defaults and ESPs cannot terminate service for nonpayment. This gives APS a competitive advantage because it has the inside credit status of the customer and it has the option of serving that customer either under its standard offer or through its affiliate, depending on the customer's payment and credit history. APS is risk free and only it has these advantages.

Q. IS THERE OTHER CUSTOMER INFORMATION WHICH GIVES APS AN ADVANTAGE?

A. Yes, APS has access to the customers power usage history. By reviewing that history, APS can target those customers that have attractive load factors or volumes for discount or competitive sales through its affiliate. That preferred customer list rests solely with APS and it is anticompetitive because competitors don't have access to that information. Competitors must guess which customers might have "marketable" load, request written authorization of that information (which is disclosed to APS), and then try to reach an agreement. Even though APS claims it will write its own code of conduct, this information might already be shared with APS's affiliate. All competitors should receive any information, such as prospect lists and customer load data, that APS Energy Services has already received. No future data should be shared between APS and APS Energy Services, except as required under the Rules.

X. DEADLINES

Q. THE AGREEMENT CONTAINS AN AUGUST 1, 1999 DEADLINE FOR COMMISSION APPROVAL, WHAT IS YOUR OBSERVATION?

A. APS and the other settling parties want to limit public input. As I mentioned earlier, APS is writing its own rules through this Agreement. The Commission has taken several years to make sure that everyone would have a fair opportunity to choose and compete. Because of all the barriers and anti-competitive effects, it is apparent that the settling parties do not want to give anyone enough time to assess the full impact of this Agreement. If it remains unmodified, it will bind future Commissioners through the year 2004 and beyond. These are far reaching consequences. APS, of course, would not like to give up the competitive advantages it has created for itself in this Agreement.

Q. WHAT WOULD HAPPEN IF THE COMMISSION WOULD MODIFY THIS AGREEMENT OR NOT MEET THE AUGUST 1, 1999 DEADLINE?

A. Settlements are negotiated all the time. This is the second written Agreement APS has negotiated in the last few months. Before there is a settlement, APS must negotiate with alternative providers, particularly those that have a serious interest in marketing to <u>all customers</u> in Arizona. This Settlement has not considered the impacts on competition, because it has not included providers with experience in the electric competitive market. Consequently, the Commission should reject this Settlement and urge the settling parties to negotiate with alternative providers and also reinstate the expedited schedule for establishing the stranded costs, standard offer and unbundled tariffs and reinstate the affiliate transaction rules.

XI. DIRECT ACCESS TARIFFS

Q. DO YOU HAVE COMMENTS REGARDING THE DIRECT ACCESS TARIFFS?

A. Yes, the "basic delivery service" charge should be eliminated. With unbundled tariffs, there is no need for noncost-based charges such as this basic delivery service component. APS and the other utilities should be encouraged to focus on the distribution or other specific service they are providing and the costs associated with that service. This is the only way to force APS to focus on cost efficiencies. Allowing these fringe extra charges encourages cost-shifting and the padding of expenditures. If this charge is made on all residential customers, APS would be collecting an extra $6.85 million per month without attributing that charge to any function. This is a windfall to APS's shareholders and should be rejected as not being in the public interest.

Q. HOW DO THESE DIRECT ACCESS TARIFFS ADDRESS THE GENERATION SHOPPING CREDIT?

A. The direct access tariffs do not include a generation shopping credit. APS apparently does not wish to disclose how much unbundled generation costs are actually being paid by its customers. As I mentioned before, an actual cost-of-service study to unbundle these transmission, distribution, generation, and other activities performed by APS is needed. Otherwise, APS could have manipulated those costs. The public needs to know if these total costs add up. Customers need to be able to make an informed comparison of these unbundled elements and be assured that they will pay the same – except for that component they might purchase from a competitor. The Commission needs to perform its obligation to the public in assuring them that these regulated rates are "just and reasonable" and not use numbers negotiated by APS with a couple selected parties.

Q. WHAT ARE YOUR OBSERVATIONS REGARDING THE METERING, METERING READING OR CONSOLIDATED BILLING CREDITS?

A. These credits are meaningless. The billing credit is 30 cents per month, not even enough to cover the cost of a postage stamp. APS's billing costs per customer are obviously more than 30 cents per month. Edison in California uses $1.41 per month and it has been proven that amount doesn't cover the billing costs of personnel, paper, postage and overhead. APS should not be able to use these arbitrary credits, it should credit customers the full allocated cost-of-service associated with each of these metering, meter reading, or consolidated billing functions. This low billing credit clearly shows that APS has shifted some of those costs to some other function.

Q. WHAT ARE YOUR COMMENTS ABOUT THE DIRECT ACCESS GENERAL SERVICE TARIFF?

A. The rate structure is too complex. It does not give a clear price signal to customers because of the staging of kilowatt and kilowatt per hour costs. As I mentioned previously, the basic delivery service charge must be deleted because it is not reflective of any costs directly incurred by APS.

Q. IN REFERENCE TO THE EXTRA LARGE GENERAL SERVICE DIRECT ACCESS TARIFF, WHAT ARE YOUR COMMENTS?

A. Again the basic delivery service charge should be deleted as corresponding to any actual cost-of-service performed by APS and allocated to a particular function.

XII. CONCLUSION AND SUMMARY

Q. SHOULD THE COMMISSION APPROVE THIS AGREEMENT WITHOUT MODIFICATION?

A. No, the Commission should reject this APS Settlement Agreement in its entirety. It could then encourage those self-appointed settling parties to negotiate with all interest groups, and in the meantime, the Commission should establish the hearing schedule on APS's unbundled tariffs and stranded costs.

Q. SHORT OF REJECTING THE SETTLEMENT IN TOTAL, PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. I recommend that the Settlement Agreement be modified with these changes:

1. Customer Access (Sec. 1.2): All APS customers should have immediate access to electric competition, not just a few, on the effective date of the Settlement. APS's self-imposed limits conflicts with the Rules. The Rules should include the third-party oral verification process so that customers can easily switch to alternative providers.

2. Unbundled Tariffs (Sec. 2.1): All costs of APS must be clearly defined so that customers are assured that they are paying the true cost for services they purchase from APS. This requires a current cost-of-service analysis subject to the ratemaking procedures of the Commission which could occur in an expedited manner. The transmission and distribution charges must be the same for unbundled Standard Offer rates and the Direct Access rates. There must be a pro rata cost allocation, including G&A, overhead and allowed return, on both the unbundled Standard Offer rates and the Direct Access rates.

3. Generation Shopping Credit (Art. II): APS should not be able to set its own distribution rates by not disclosing what its costs of generation is for standard offer customers. The standard offer must be unbundled so that the appropriate costs for distribution, transmission, generation and other services are clearly segregated. Otherwise competitive customers will likely be subsidizing the generation costs of APS which it might sell back to its standard offer customers or to other customers in or outside of Arizona.

4. Stranded Costs (Art. III): Selection of the $350 million stranded cost figure does not relate to any prior evidence or testimony in these proceedings. Substantial evidence and

testimony indicate that APS may have negative stranded costs associated with its generation. The Commission should determine the assumptions and basis any stranded cost recovery, after it has unbundled the functional costs of APS and conducted a hearing on stranded costs.

5. Regulatory Assets (Art. III): Regulatory assets must be verified and included as part of the competitive transition charge, not as a component of the distribution charge.

6. Affiliate Transaction Rules (Art. IV): The recently deleted affiliate transaction rules should be reinstated. APS should not be able to compete, either by offering discount rates to standard offer customers or through its competitive affiliate, until those affiliate rules are in place and the rates are unbundled as indicated above.

7. Divestiture of Generation Assets (Secs. 4.2 & 4.4): APS should be prohibited from transferring its generation assets to a "paper" affiliate. APS should be required to divest itself of generation assets, by auction and appraisal, so as to avoid the market power retained by APS in its service area and Arizona in general.

8. Waiver of Commission Statutes (Sec. 4.3): Arizona laws pertaining to APS should not be waived, and Commonwealth questions whether or not the Commission has the authority to waive laws passed by the Arizona legislature that protect consumers and competitors.

9. Arizona Statutes and Commission Rules (Sec. 7.1): The Arizona statutes and Commission rules should control, not the terms and conditions negotiated by APS with a few of its customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

	PALO VERDE			
	FIRM		NON-FIRM	
DATE	ON	OFF	ON	OFF
1/1/98	$ 16.00	$ 16.50	$ 13.81	$ 13.89
1/2/98	$ 22.33	$ 15.59	$ 16.89	$ 13.16
1/3/98	$ 22.33	$ 15.59	$ 16.16	$ 13.66
1/4/98	$ 18.56	$ 14.00	$ 15.63	$ 14.30
1/5/98	$ 22.75	$ 14.00	$ 24.22	$ 14.63
1/6/98	$ 23.68	$ 14.50	$ 25.73	$ 17.45
1/7/98	$ 26.59	$ 17.00	$ 24.51	$ 20.59
1/8/98	$ 28.68	$ 17.00	$ 23.28	$ 17.86
1/9/98	$ 27.31	$ 15.50	$ 35.98	$ 18.62
1/10/98	$ 27.47	$ 16.50	$ 25.90	$ 19.37
1/11/98	$ 25.00	$ 18.00	$ 20.49	$ 18.83
1/12/98	$ 28.60	$ 17.50	$ 30.24	$ 18.36
1/13/98	$ 28.78	$ 17.50	$ 21.55	$ 17.99
1/14/98	$ 25.05	$ 16.75	$ 20.70	$ 16.60
1/15/98	$ 23.20	$ 16.00	$ 19.42	$ 17.17
1/16/98	$ 23.07	$ 16.00	$ 19.08	$ 14.23
1/17/98	$ 21.79	$ 16.00	$ 15.18	$ 12.98
1/18/98	$ 19.90	$ 16.50	$ 13.09	$ 12.61
1/19/98	$ 22.78	$ 12.78	$ 17.83	$ 13.62
1/20/98	$ 22.00	$ 14.25	$ 19.84	$ 14.04
1/21/98	$ 21.12	$ 16.50	$ 18.15	$ 14.10
1/22/98	$ 19.27	$ 14.00	$ 16.48	$ 13.15
1/23/98	$ 18.24	$ 13.25	$ 16.35	$ 11.70
1/24/98	$ 18.44	$ 13.25	$ 14.98	$ 12.59
1/25/98	$ 15.33	$ 12.50	$ 13.28	$ 12.64
1/26/98	$ 19.47	$ 12.94	$ 18.12	$ 12.33
1/27/98	$ 18.15	$ 14.00	$ 15.67	$ 11.32
1/28/98	$ 18.30	$ 14.00	$ 16.06	$ 12.25
1/29/98	$ 17.26	$ 13.00	$ 16.22	$ 12.58
1/30/98	$ 15.27	$ 11.41	$ 16.24	$ 12.45
1/31/98	$ 15.30	$ 11.25	$ 16.34	$ 12.38
Avg	$ 21.68	$ 14.95	$ 19.27	$ 14.76
2/1/98	$ 14.29	$ 13.95	$ 15.93	$ 11.79
2/2/98	$ 19.45	$ 11.00	$ 20.06	$ 12.35
2/3/98	$ 22.43	$ 12.78	$ 19.54	$ 12.57
2/4/98	$ 20.63	$ 10.50	$ 18.14	$ 10.86
2/5/98	$ 21.13	$ 12.00	$ 19.21	$ 11.06
2/6/98	$ 18.09	$ 10.92	$ 17.80	$ 11.41
2/7/98	$ 18.22	$ 10.92	$ 15.16	$ 11.91
2/8/98	$ 18.25	$ 11.50	$ 14.65	$ 11.74
2/9/98	$ 21.33	$ 11.00	$ 21.11	$ 11.56
2/10/98	$ 21.52	$ 12.50	$ 21.20	$ 12.67
2/11/98	$ 22.27	$ 13.00	$ 19.99	$ 12.25
2/12/98	$ 24.14	$ 13.30	$ 18.89	$ 13.03
2/13/98	$ 23.75	$ 13.00	$ 19.54	$ 11.20
2/14/98	$ 18.06	$ 12.91	$ 14.51	$ 10.58
2/15/98	$ 18.13	$ 12.16	$ 12.63	$ 9.97
2/16/98	$ 20.93	$ 11.80	$ 20.37	$ 10.90

Fred,
Here are Palo Verde
Prices for 1998.
Anthony

EXHIBIT
Commonwealth
9
~~Admitted~~

	PALO VERDE			
	FIRM		NON-FIRM	
DATE	ON	OFF	ON	OFF
2/17/98	$ 20.81	$ 11.50	$ 22.09	$ 10.60
2/18/98	$ 21.75	$ 12.50	$ 18.76	$ 11.13
2/19/98	$ 20.21	$ 11.45	$ 17.93	$ 10.98
2/20/98	$ 16.83	$ 11.00	$ 18.66	$ 10.81
2/21/98	$ 16.85	$ 11.00	$ 13.27	$ 10.05
2/22/98	$ 15.00	$ 11.95	$ 11.69	$ 10.21
2/23/98	$ 18.35	$ 11.20	$ 19.92	$ 11.32
2/24/98	$ 23.59	$ 13.04	$ 19.83	$ 11.15
2/25/98	$ 22.38	$ 12.25	$ 18.43	$ 10.79
2/26/98	$ 20.88	$ 11.90	$ 18.04	$ 11.04
2/27/98	$ 19.13	$ 10.88	$ 15.88	$ 11.85
2/28/98	$ 18.96	$ 10.92	$ 13.23	$ 11.30
Avg	$ 19.91	$ 11.89	$ 17.73	$ 11.32
3/1/98	$ 15.17	$ 12.00	$ 12.06	$ 10.39
3/2/98	$ 22.35	$ 11.75	$ 17.52	$ 10.10
3/3/98	$ 22.30	$ 12.25	$ 16.66	$ 9.75
3/4/98	$ 20.65	$ 11.36	$ 18.31	$ 9.56
3/5/98	$ 23.50	$ 12.15	$ 17.09	$ 10.32
3/6/98	$ 19.34	$ 11.82	$ 14.35	$ 10.25
3/7/98	$ 19.29	$ 12.11	$ 12.93	$ 10.71
3/8/98	$ 16.00	$ 11.00	$ 12.16	$ 12.02
3/9/98	$ 18.90	$ 11.32	$ 17.39	$ 11.81
3/10/98	$ 19.30	$ 11.25	$ 18.36	$ 13.65
3/11/98	$ 20.55	$ 11.50	$ 15.83	$ 11.03
3/12/98	$ 20.11	$ 13.52	$ 16.35	$ 12.03
3/13/98	$ 19.40	$ 13.58	$ 17.89	$ 11.02
3/14/98	$ 19.11	$ 13.05	$ 18.74	$ 12.76
3/15/98	$ 16.75	$ 13.00	$ 18.60	$ 12.71
3/16/98	$ 21.18	$ 13.00	$ 23.29	$ 14.21
3/17/98	$ 21.96	$ 13.30	$ 24.82	$ 16.18
3/18/98	$ 23.89	$ 14.12	$ 20.46	$ 14.02
3/19/98	$ 24.07	$ 13.63	$ 27.65	$ 18.44
3/20/98	$ 23.65	$ 14.99	$ 23.43	$ 15.95
3/21/98	$ 23.08	$ 15.24	$ 18.50	$ 15.33
3/22/98	$ 19.00	$ 15.26	$ 17.09	$ 14.25
3/23/98	$ 24.73	$ 15.30	$ 21.69	$ 14.20
3/24/98	$ 23.74	$ 15.10	$ 23.90	$ 14.39
3/25/98	$ 22.19	$ 14.50	$ 21.38	$ 14.29
3/26/98	$ 25.39	$ 14.75	$ 19.84	$ 12.82
3/27/98	$ 22.58	$ 14.00	$ 17.00	$ 11.47
3/28/98	$ 22.56	$ 14.00	$ 17.44	$ 10.87
3/29/98	$ 18.08	$ 13.75	$ 15.91	$ 10.57
3/30/98	$ 21.57	$ 13.23	$ 19.27	$ 11.02
3/31/98	$ 22.75	$ 13.66	$ 19.07	$ 13.07
Avg	$ 21.07	$ 13.21	$ 18.55	$ 12.55
4/1/98	$ 23.90	$ 12.50	$ 19.22	$ 12.15
4/2/98	$ 23.83	$ 13.55	$ 19.99	$ 14.23
4/3/98	$ 23.14	$ 13.25	$ 21.07	$ 12.26

	PALO VERDE							
	FIRM				NON-FIRM			
DATE	ON		OFF		ON		OFF	
4/4/98	$	22.79	$	13.25	$	19.62	$	13.58
4/5/98	$	19.00	$	13.25	$	14.67	$	14.34
4/6/98	$	24.11	$	13.26	$	20.23	$	14.56
4/7/98	$	24.22	$	13.35	$	25.55	$	19.43
4/8/98	$	24.02	$	14.35	$	24.06	$	20.01
4/9/98	$	23.94	$	14.34	$	25.29	$	10.03
4/10/98	$	23.38	$	14.50	$	22.72	$	16.73
4/11/98	$	23.37	$	14.50	$	21.48	$	15.44
4/12/98	$	22.55	$	14.83	$	17.68	$	15.54
4/13/98	$	24.51	$	14.90	$	22.64	$	15.97
4/14/98	$	24.84	$	15.00	$	27.60	$	15.84
4/15/98	$	24.85	$	14.94	$	30.66	$	15.16
4/16/98	$	24.99	$	15.00	$	32.32	$	20.74
4/17/98	$	26.18	$	16.33	$	27.28	$	19.31
4/18/98	$	25.85	$	16.00	$	23.60	$	20.29
4/19/98	$	23.28	$	16.00	$	21.79	$	17.05
4/20/98	$	28.35	$	16.00	$	30.72	$	10.37
4/21/98	$	30.72	$	17.15	$	30.26	$	15.36
4/22/98	$	29.73	$	15.00	$	23.54	$	13.76
4/23/98	$	26.77	$	15.00	$	25.52	$	13.94
4/24/98	$	25.87	$	14.38	$	23.16	$	13.65
4/25/98	$	25.79	$	14.38	$	13.90	$	11.57
4/26/98	$	20.58	$	13.00	$	14.52	$	10.18
4/27/98	$	26.81	$	14.00	$	21.09	$	10.63
4/28/98	$	27.18	$	13.02	$	20.08	$	11.09
4/29/98	$	27.78	$	10.67	$	22.72	$	13.38
4/30/98	$	26.63	$	11.67	$	26.36	$	13.80
Avg	$	24.97	$	14.25	$	22.98	$	14.68
5/1/98	$	24.66	$	11.32	$	21.48	$	13.05
5/2/98	$	24.63	$	11.32	$	13.37	$	11.48
5/3/98	$	18.00	$	11.00	$	13.12	$	9.81
5/4/98	$	23.72	$	11.19	$	22.73	$	9.57
5/5/98	$	21.68	$	7.94	$	19.13	$	9.13
5/6/98	$	23.13	$	9.96	$	17.42	$	9.79
5/7/98	$	22.26	$	9.32	$	14.86	$	8.65
5/8/98	$	17.77	$	7.38	$	15.83	$	8.50
5/9/98	$	17.77	$	7.38	$	18.74	$	12.42
5/10/98	$	17.17	$	6.60	$	12.98	$	8.75
5/11/98	$	23.64	$	6.60	$	18.17	$	8.65
5/12/98	$	20.60	$	5.96	$	13.92	$	8.07
5/13/98	$	19.98	$	5.25	$	17.22	$	8.00
5/14/98	$	17.38	$	6.23	$	12.80	$	7.37
5/15/98	$	16.46	$	6.04	$	12.62	$	9.03
5/16/98	$	16.46	$	6.04	$	12.54	$	9.11
5/17/98	$	15.70	$	6.00	$	12.41	$	8.74
5/18/98	$	22.02	$	6.75	$	25.31	$	9.40
5/19/98	$	20.16	$	6.63	$	24.71	$	12.22
5/20/98	$	25.06	$	9.57	$	17.78	$	9.33

	PALO VERDE							
	FIRM				NON-FIRM			
DATE	ON		OFF		ON		OFF	
5/21/98	$	26.27	$	7.67	$	17.90	$	9.28
5/22/98	$	26.30	$	7.50	$	18.07	$	10.13
5/23/98	$	16.53	$	7.25	$	9.25	$	8.35
5/24/98	$	16.62	$	7.06	$	8.10	$	7.50
5/25/98	$	11.39	$	6.34	$	11.12	$	7.60
5/26/98	$	21.35	$	6.63	$	13.70	$	9.07
5/27/98	$	19.88	$	6.88	$	14.15	$	7.71
5/28/98	$	20.76	$	6.54	$	14.83	$	8.48
5/29/98	$	20.66	$	6.54	$	19.56	$	9.26
5/30/98	$	13.68	$	6.22	$	14.00	$	8.91
5/31/98	$	9.62	$	6.22	$	9.67	$	6.86
Avg	$	19.72	$	7.53	$	15.73	$	9.17
6/1/98	$	24.28	$	7.51	$	23.06	$	8.00
6/2/98	$	26.38	$	7.27	$	20.61	$	7.78
6/3/98	$	25.38	$	7.23	$	12.58	$	7.43
6/4/98	$	22.46	$	5.33	$	9.73	$	7.04
6/5/98	$	15.46	$	4.42	$	13.12	$	6.90
6/6/98	$	15.46	$	4.38	$	10.53	$	7.11
6/7/98	$	8.56	$	4.49	$	10.10	$	8.49
6/8/98	$	19.83	$	4.63	$	9.89	$	8.09
6/9/98	$	17.86	$	4.50	$	10.09	$	5.65
6/10/98	$	14.80	$	4.80	$	9.75	$	5.22
6/11/98	$	12.51	$	4.54	$	12.00	$	7.54
6/12/98	$	10.10	$	4.50	$	12.86	$	5.50
6/13/98	$	9.62	$	4.50	$	9.70	$	5.33
6/14/98	$	11.75	$	4.75	$	12.22	$	8.32
6/15/98	$	18.17	$	4.75	$	17.37	$	6.44
6/16/98	$	20.09	$	4.75	$	17.24	$	6.99
6/17/98	$	24.12	$	7.50	$	13.31	$	8.24
6/18/98	$	23.82	$	7.50	$	15.18	$	7.34
6/19/98	$	20.30	$	9.00	$	20.73	$	8.78
6/20/98	$	20.06	$	8.78	$	13.41	$	11.30
6/21/98	$	23.54	$	8.83	$	17.55	$	7.96
6/22/98	$	26.98	$	9.00	$	27.03	$	8.15
6/23/98	$	26.54	$	9.00	$	20.73	$	10.63
6/24/98	$	25.69	$	8.65	$	15.94	$	8.40
6/25/98	$	25.20	$	7.50	$	16.02	$	9.06
6/26/98	$	20.08	$	8.25	$	16.03	$	8.67
6/27/98	$	20.03	$	8.25	$	17.90	$	9.40
6/28/98	$	26.00	$	8.50	$	19.79	$	10.27
6/29/98	$	25.74	$	8.50	$	44.81	$	11.57
6/30/98	$	26.99	$	8.50	$	20.19	$	9.87
Avg	$	20.26	$	6.67	$	16.32	$	8.05
7/1/98	$	42.81	$	13.50	$	19.65	$	11.57
7/2/98	$	42.49	$	12.99	$	21.53	$	11.17
7/3/98	$	34.75	$	13.01	$	12.74	$	10.40
7/4/98	$	28.29	$	12.32	$	22.29	$	10.55
7/5/98	$	21.35	$	13.00	$	15.76	$	10.90

	PALO VERDE			
	FIRM		NON-FIRM	
DATE	ON	OFF	ON	OFF
7/6/98	$ 35.63	$ 13.26	$ 27.65	$ 10.92
7/7/98	$ 35.36	$ 13.15	$ 27.80	$ 13.20
7/8/98	$ 34.24	$ 13.58	$ 27.30	$ 13.59
7/9/98	$ 39.41	$ 14.68	$ 29.26	$ 14.90
7/10/98	$ 32.20	$ 15.50	$ 22.40	$ 16.32
7/11/98	$ 31.51	$ 15.50	$ 33.04	$ 25.55
7/12/98	$ 20.29	$ 15.00	$ 28.38	$ 18.05
7/13/98	$ 38.37	$ 15.43	$ 42.27	$ 23.94
7/14/98	$ 49.71	$ 18.23	$ 33.87	$ 32.83
7/15/98	$ 57.86	$ 17.94	$ 33.16	$ 14.81
7/16/98	$ 47.93	$ 18.67	$ 42.63	$ 17.13
7/17/98	$ 48.17	$ 18.23	$ 36.03	$ 23.24
7/18/98	$ 46.21	$ 18.42	$ 21.52	$ 20.02
7/19/98	$ 34.33	$ 18.00	$ 32.15	$ 23.02
7/20/98	$ 63.48	$ 22.49	$ 31.39	$ 19.89
7/21/98	$ 61.86	$ 26.14	$ 25.13	$ 20.54
7/22/98	$ 45.11	$ 24.18	$ 23.89	$ 17.80
7/23/98	$ 33.58	$ 20.43	$ 22.12	$ 16.62
7/24/98	$ 26.69	$ 16.28	$ 28.86	$ 16.83
7/25/98	$ 26.37	$ 16.01	$ 29.10	$ 17.68
7/26/98	$ 27.48	$ 18.32	$ 38.41	$ 26.44
7/27/98	$ 36.09	$ 18.32	$ 48.06	$ 19.89
7/28/98	$ 51.26	$ 20.00	$ 49.17	$ 22.33
7/29/98	$ 57.21	$ 23.00	$ 28.48	$ 24.62
7/30/98	$ 41.11	$ 26.97	$ 26.06	$ 22.79
7/31/98	$ 41.14	$ 27.45	$ 24.05	$ 16.06
Avg	$ 39.75	$ 17.74	$ 29.17	$ 18.18
8/1/98	$ 35.84	$ 22.87	$ 23.76	$ 16.88
8/2/98	$ 33.64	$ 25.00	$ 16.28	$ 16.69
8/3/98	$ 55.73	$ 26.34	$ 49.14	$ 22.08
8/4/98	$ 68.85	$ 25.00	$ 54.98	$ 20.18
8/5/98	$ 54.90	$ 30.00	$ 67.91	$ 33.02
8/6/98	$ 70.02	$ 27.00	$ 24.39	$ 24.15
8/7/98	$ 59.70	$ 21.00	$ 22.28	$ 16.69
8/8/98	$ 57.43	$ 21.00	$ 20.94	$ 16.67
8/9/98	$ 34.18	$ 9.00	$ 21.69	$ 18.97
8/10/98	$ 52.39	$ 28.00	$ 26.47	$ 14.64
8/11/98	$ 49.54	$ 18.50	25.73	14.46
8/12/98	$ 54.05	$ 18.50	29.28	21.36
8/13/98	$ 58.56	$ 24.75	32.06	25.5
8/14/98	$ 61.70	$ 23.50	24.91	20.9
8/15/98	$ 58.65	$ 23.50	22.69	22.45
8/16/98	$ 34.00	$ 24.50	23.6	24.61
8/17/98	$ 54.57	$ 27.00	24.7	24.5
8/18/98	$ 39.31	$ 24.50	22.98	25
8/19/98	$ 36.21	$ 18.50	21.9	12.95
8/20/98	$ 37.66	$ 18.50	23.21	17.44
8/21/98	$ 35.84	$ 18.50	31.84	19.57

	PALO VERDE			
	FIRM		NON-FIRM	
DATE	ON	OFF	ON	OFF
8/22/98	$ 33.94	$ 18.50	48.39	27.63
8/23/98	$ 25.00	$ 24.50	57	20.61
8/24/98	$ 43.76	$ 24.50	39.9	22.48
8/25/98	$ 47.16	$ 23.00	27.32	22.31
8/26/98	$ 64.37	$ 25.00	30.46	25.19
8/27/98	$ 56.14	$ 25.00	26.33	20.65
8/28/98	$ 44.12	$ 25.00	27.79	24.5
8/29/98	$ 41.07	$ 25.00	21.28	19.71
8/30/98	$ 35.00	$ 25.00	28.47	24.87
8/31/98	$ 57.11	$ 25.00	61.79	23.03
Avg	$ 48.08	$ 23.10	$ 31.60	$ 21.28
9/1/98	$ 98.89	$ 32.50	113.72	25
9/2/98	$ 93.84	$ 32.00	64.83	26.01
9/3/98	$ 89.07	$ 27.00	48.21	24.38
9/4/98	$ 90.22	$ 27.00	33.12	21.36
9/5/98	$ 56.18	$ 40.00	20.4	20.72
9/6/98	$ 50.23	$ 26.00	22.03	18.33
9/7/98	$ 43.00	$ 40.00	20.01	18.06
9/8/98	$ 56.22	$ 26.50	24.84	18.71
9/9/98	$ 41.61	$ 26.50	24.37	10
9/10/98	$ 41.38	$ 26.50	21.3	19.1
9/11/98	$ 32.22	$ 23.00	20.94	16.55
9/12/98	$ 32.26	$ 23.00	19.56	13
9/13/98	$ 28.52	$ 23.00	19.34	25
9/14/98	$ 34.27	$ 23.00	21.84	18.63
9/15/98	$ 32.56	$ 24.00	20.23	13.78
9/16/98	$ 30.34	$ 23.75	20.2	15.46
9/17/98	$ 28.75	$ 22.50	20.1	13.62
9/18/98	$ 26.06	$ 19.50	21.5	13.42
9/19/98	$ 25.82	$ 19.50	24.79	18.49
9/20/98	$ 24.94	$ 19.50	18.02	15.12
9/21/98	$ 30.60	$ 19.00	20.91	13.4
9/22/98	$ 30.77	$ 20.00	21.45	13.13
9/23/98	$ 28.55	$ 16.25	22.98	15.33
9/24/98	$ 27.57	$ 16.25	21.28	17.75
9/25/98	$ 25.47	$ 20.00	20.12	12.49
9/26/98	$ 24.86	$ 20.00	15.95	11.74
9/27/98	$ 22.50	$ 17.00	14.42	11.79
9/28/98	$ 26.09	$ 17.00	23.75	12.56
9/29/98	$ 25.22	$ 17.50	23.43	14.12
9/30/98	$ 25.31	$ 19.50	22.2	13.2
Avg	$ 40.78	$ 23.58	$ 26.86	$ 16.68
10/1/98	$ 25.46	$ 16.58	22.02	14.32
10/2/98	$ 25.32	$ 15.28	21.29	13.55
10/3/98	$ 25.35	$ 15.28	26.22	14
10/4/98	$ 20.50	$ 15.00	20	13.03
10/5/98	$ 25.75	$ 15.91	20.55	11.73
10/6/98	$ 25.90	$ 12.96	19.04	12.46

	PALO VERDE			
	FIRM		NON-FIRM	
DATE	ON	OFF	ON	OFF
10/7/98	$ 26.71	$ 13.30	22.27	12.22
10/8/98	$ 27.26	$ 14.83	24.35	14.35
10/9/98	$ 25.67	$ 16.00	24.05	15.72
10/10/98	$ 25.31	$ 16.00	18.6	12.94
10/11/98	$ 26.63	$ 16.00	17.39	12.52
10/12/98	$ 26.48	$ 15.63	22.61	13.79
10/13/98	$ 26.18	$ 14.00	27.6	14.24
10/14/98	$ 25.77	$ 12.17	28.3	14.56
10/15/98	$ 27.18	$ 15.33	22.72	13.85
10/16/98	$ 27.18	$ 15.00	23.46	12.98
10/17/98	$ 26.20	$ 14.91	19.55	13.65
10/18/98	$ 20.00	$ 15.83	17.47	13.68
10/19/98	$ 27.85	$ 14.50	28	12.64
10/20/98	$ 27.86	$ 15.06	26.76	14.16
10/21/98	$ 27.92	$ 15.22	30.13	15.41
10/22/98	$ 27.90	$ 15.78	23.47	16.7
10/23/98	$ 28.66	$ 17.16	26.28	15.96
10/24/98	$ 28.01	$ 15.75	24.68	15.27
10/25/98	$ 28.50	$ 16.00	19.02	14.11
10/26/98	$ 28.40	$ 17.00	31.56	15.06
10/27/98	$ 28.94	$ 15.50	28.95	16.13
10/28/98	$ 29.85	$ 16.75	26.29	15.59
10/29/98	$ 29.65	$ 16.00	20.89	15.5
10/30/98	$ 27.81	$ 14.50	21.2	15.41
10/31/98	$ 27.52	$ 14.50	15.12	14.93
Avg	$ 26.70	$ 15.28	$ 23.22	$ 14.21
11/1/98	R 25.00	$ 14.50	17.19	10.39
11/2/98	$ 24.57	$ 16.00	21.89	10.76
11/3/98	$ 27.31	$ 15.08	22.64	11.8
11/4/98	$ 28.43	$ 14.54	24.14	10.45
11/5/98	$ 28.82	$ 14.50	23.15	12.99
11/6/98	$ 26.42	$ 14.50	19.95	11.41
11/7/98	$ 26.38	$ 14.50	21.99	15.02
11/8/98	$ 20.00	$ 15.25	16.05	13.21
11/9/98	$ 29.62	$ 15.21	26.55	14.25
11/10/98	$ 28.76	$ 22.50	28.42	14.66
11/11/98	$ 28.72	$ 14.07	27.01	21.79
11/12/98	$ 28.71	$ 14.07	28.09	20.27
11/13/98	$ 27.68	$ 14.04	29.34	15.91
11/14/98	$ 27.49	$ 14.04	23.83	16.56
11/15/98	$ 20.00	$ 15.48	20.03	14.78
11/16/98	$ 29.85	$ 15.57	26.06	14.08
11/17/98	$ 30.44	$ 14.00	25.1	14.2
11/18/98	$ 29.05	$ 13.71	24.21	14.79
11/19/98	$ 27.40	$ 11.50	26.49	13.2
11/20/98	$ 26.42	$ 14.30	25.37	13.28
11/21/98	$ 26.39	$ 14.30	22.86	15
11/22/98	$ 20.42	$ 14.07	22.04	13.73

	PALO VERDE			
	FIRM		NON-FIRM	
DATE	ON	OFF	ON	OFF
11/23/98	$ 28.18	$ 14.70	33.48	19.56
11/24/98	$ 28.78	$ 16.00	23.53	17.22
11/25/98	$ 28.71	$ 16.00	22.23	16.55
11/26/98	$ 25.63	$ 15.50	15.28	13
11/27/98	$ 25.76	$ 15.50	20.41	14
11/28/98	$ 25.76	$ 17.00	13.5	11.42
11/29/98	$ 20.00	$ 14.50	23.07	10.68
11/30/98	$ 27.26	$ 15.50	23.83	14.31
Avg	$ 25.77	$ 15.01	$ 23.26	$ 14.31
12/1/98	$ 27.37	$ 15.00	22.92	14.68
12/2/98	$ 27.56	$ 13.00	21.01	13.58
12/3/98	$ 26.83	$ 13.50	20.5	14.05
12/4/98	$ 23.57	$ 13.00	20.04	13.59
12/5/98	$ 23.47	$ 13.00	19.96	12
12/6/98	$ 18.25	$ 13.50	22.15	12.54
12/7/98	$ 26.71	$ 13.50	33.17	27.5
12/8/98	$ 28.90	$ 15.70	22.78	24.76
12/9/98	$ 28.38	$ 17.48	26.43	25.51
12/10/98	$ 27.95	$ 17.66	23.65	16.97
12/11/98	$ 26.19	$ 16.00	24.72	17.64
12/12/98	$ 25.47	$ 16.00	25.51	23.65
12/13/98	$ 27.13	$ 17.19	20.58	13.46
12/14/98	$ 27.15	$ 17.21	20.59	14.93
12/15/98	$ 28.90	$ 15.70	22.78	24.76
12/16/98	$ 23.81	$ 15.25	23.56	19.88
12/17/98	$ 23.93	$ 15.00	22.93	16.61
12/18/98	$ 27.22	$ 15.50	21.99	17.05
12/19/98	$ 27.13	$ 15.25	22.28	13.07
12/20/98	$ 36.50	$ 19.50	23.54	15.1
12/21/98	$ 32.13	$ 19.75	64.52	22.09
12/22/98	$ 38.81	$ 18.37	46.89	24.57
12/23/98	$ 38.88	$ 19.83	36.49	30.02
12/24/98	$ 28.67	$ 19.25	22.63	27.04
12/25/98	$ 30.50	$ 19.33	30.5	20.25
12/26/98	$ 28.43	$ 19.25	15.15	10.87
12/27/98	$ 27.13	$ 20.25	13.14	11.17
12/28/98	$ 27.38	$ 19.19	27.31	10.6
12/29/98	$ 24.28	$ 14.69	22.15	12.33
12/30/98	$ 24.28	$ 14.69	14.3	9.04
12/31/98	$ 24.31	$ 14.69	10.91	8.24
Avg	$ 27.65	$ 16.36	$ 24.68	$ 17.34
Annual Avg	$28.03	$14.96	$22.45	$14.38

BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF TOM E. DELANEY

On Behalf of Enron Corp.

Case Nos. E-01345A-98-0473, *et. al.*

June 30, 1999

EXHIBIT
Admitted
Enron-5

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas E. Delaney. My business address is 4742 N. 24th Street, Suite 165, Phoenix, Arizona, 85016.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a Director of Government Affairs for Enron Corp

Q. What are your responsibilities as Director?

A. My primary role as a Director is interstate commerce in the west, deregulation, the creation of Independent System Operators (ISO), Transcos, Independent Scheduling Administrators (ISA) and most issues as they pertain to Federal Regulatory Affairs and electrical interstate commerce.

Q. What is your background and other experience?

R. I have three Bachelors of Business Administration degrees from the University of Portland, one in marketing, one in management and one in accounting. I have more than 10 years experience in the energy industry. Before joining Enron, I was employed with Bonneville Power Administration, from 1990 to 1997. My experience with Bonneville included power revenue determinations, contract negotiations, field management, and California electrical restructuring. With Bonneville, I represented Northwest issues in the California ISO and Power Exchange (Px) creation and development. I served on both California ISO and Px Trust Advisory Committees and served as out-of state Technical Advisor to the California ISO Board of Directors. More recently, I have played a key role in the creation of the Arizona ISA and serve as a director on its Board. I currently serve on the Mountain West ISA Steering Committee, the Desert STAR Steering

Committees and working groups. I am also involved in the restructuring of ERCOT and the structuring of new RTO's in the Pacific Northwest and Florida. I have also been asked to serve on an interim board for Desert STAR.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. As discussed in the testimony of Dr. Mark Frankena, the settlement agreement between Arizona Public Service Company and the other settling parties creates the opportunity for APS to exercise market power in the Phoenix load pocket. Dr. Frankena's testimony also indicates that there may be a possibility that this market power extends beyond the Phoenix load pocket. In my testimony, I propose a series of market power mitigation measures that should be imposed on APS by the Commission. These mitigation measures are intended to protect the wholesale marketplace and will provide substantial benefits for the retail marketplace. Without these mitigation measures, there is a substantial likelihood that the APS generating affiliate will be able to control pricing and supply of energy in the wholesale market. The ability to exercise this control will impair the ability of energy service providers such as Enron to procure and supply cost-effective commodity to retail and wholesale customers in Arizona.

Q. DOES ENRON SUPPORT ADOPTION OF THE SETTLEMENT AGREEMENT?

A. Enron opposes adoption of the settlement agreement by the Commission. As indicated in the testimony of the other Enron witnesses, Dr. Alan Rosenberg, Mr. Harry Kingerski and Dr. Mark Frankena, the settlement agreement raises too many unanswered questions and leaves too many unaddressed issues for the Commission to find that the settlement agreement is in the public interest. If implemented without Commission imposed conditions and modifications, the settlement agreement is likely to lead to substantial ratepayer harm and a noncompetitive wholesale and retail marketplace.

Q. WHAT PROVISIONS OF THE SETTLEMENT AGREEMENT WILL YOU ADDRESS IN YOUR TESTIMONY?

A. My testimony will address the provisions that: (1) allow APS to transfer all of its generating resources to a generation affiliate at book value; and (2) set forth the parties support for the APS generation affiliate to charge market-based rates. I will also address the provisions of the settlement agreement that require APS to participate in the Arizona ISA.

Q. WHAT ARE ENRON'S CONCERNS WITH THE PROPOSAL TO TRANSFER ALL OF APS GENERATING FACILITIES TO THE GENERATION AFFILIATE AT BOOK VALUE (AND THE PROVISIONS REQUIRING PARTIES TO SUPPORT MARKET-BASED PRICING FOR THE AFFILIATE)?

A. We have several concerns with the proposed transfer of APS's generating facilities to its generating affiliate. First, as discussed by Dr. Rosenberg, the transfer at book value can negatively affect customers of both APS (as the default provider) and APS (as the wires services provider). Customers will end up subsidizing the generation affiliate: (1) to the extent the stranded cost number identified in the settlement overstates stranded costs; (2) to the extent the transfer of all costs associated with the generation assets are not transferred to the generation affiliate; (3) to the extent the capital structure isn't properly developed for the generation affiliate; and (4) to the extent the tax effects of the stranded cost determination in the settlement agreement (or the transfer of the assets) are allowed to flow to Pinnacle West (and lost to the ratepayers).

Second, we have a number of concerns with the notion itself—*i.e.*, that a utility can transfer assets to its affiliate generation assets at book value. Recent auctions of non-nuclear generation facilities show that generation resources often have a market value that is in excess of book value and that auctions are the best way of determining stranded costs. Depending on how the transfer is implemented, it can have the effect of placing the generation affiliate, which will be an unregulated competitor, in a superior competitive position to generation companies forced to build green-field facilities in Arizona or purchase generation resources outside of Arizona. Further, because of transmission pricing in the region, this transfer at book value can place the generation affiliate in a superior competitive position to power marketers such as Enron that will be forced to purchase energy outside the region and move it into Arizona. Power marketers will have to pay transmission rates for wheeling power into Arizona that the APS affiliate can avoid because of the location of APS's generating assets in Arizona.

Third, as discussed more fully in the testimony of Dr. Frankena, the transfer of APS's generating assets to the APS generation affiliate will result in the generation affiliate having market power in the Phoenix area load pocket. Because it will have market power in the load pocket, the APS generation affiliate can "run up the price" of commodity within the Phoenix area load pocket during periods where transmission congestion prevents competitive entry from generation outside the load pocket. Further, the APS generation affiliate can withhold energy to prevent competitors from consummating transactions or supplying their customers with energy during peak periods.

Q. DOES ENRON HAVE ANY RECOMMENDATIONS CONCERNING THE POTENTIAL FOR RATEPAYER SUBSIDIZATION OF THE GENERATION AFFILIATE?

A. Yes. These recommendations are included in the testimony of Dr. Rosenberg.

Q. DOES ENRON HAVE ANY RECOMMENDATIONS FOR ADDRESSING THE POTENTIAL COMPETITIVE ADVANTAGE GIVEN TO THE APS GENERATION AFFILIATE BY THE ASSET TRANSFER?

A. Yes, we have several recommendations. First, we strongly recommend that the Commission impose a strong code of conduct requirement as a condition of approving the settlement agreement. Enron's recommendation concerning code of conduct are set forth by Mr. Kingerski.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS?

A. Yes. The Commission should also impose a generation company standard of conduct. The generation standard of conduct should require the generation affiliate to sell a substantial portion of the output of the generation owned by the APS affiliate to non-affiliated purchasers. Requiring the APS generation affiliate to track power sales through the calendar year and report all sales made directly to APS affiliates on an annual basis to the Commission should enforce the standard of conduct. Sales made by brokers to APS affiliates or sales of the APS affiliates generation to other affiliates that are a result of blind match transactions such as NYMEX futures can be excluded from the report.

If implemented, this recommendation should blunt the competitive advantage that will be enjoyed by the APS generation affiliate and any Pinnacle West affiliates (including APS) participating in the Arizona markets. The provision should put all purchasers of output in the market on an equal footing.

HOW DO YOU SUGGEST THE COMMISSION ADDRESS THE MARKET POWER CONCERNS RAISED BY DR. FRANKENA?

A. Our strongest recommendation is that the Commission order APS to divest its generating resources through an auction or other means. We recommend that the resources be split into several bundles, similar to the approach taken by Nevada Power Company and Sierra Pacific Power Company in Nevada. An excerpt from the plan as filed in Docket No. 98-7023 is attached as Exhibit TED-1 for illustrative purposes.[1] The bundles should be developed in a way that prevents any single purchaser from gaining market power by virtue of the purchase. For example, a sale of an APS generating facility to the Salt River Project could exacerbate rather than mitigate market power.

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[1] The parties to this docket recently stipulated to a change in the bundles proposed by Nevada Power Company. As a result of the stipulation, Nevada Power Company will auction four bundles rather than the three proposed in their filing. The increase in the number of bundles addresses PUCN staff

While we recognize that divestiture has been proposed and rejected in this Commission's restructuring dockets in the past, we continue to urge the Commission to order divestiture. By selling the resources in several bundles, no single purchaser will hold market power in the Phoenix area load pocket or in Northern Arizona in general. The resulting wholesale market for Phoenix and Northern Arizona will be more competitive and consumers will ultimately benefit. We also note that divestiture will provide the best and most reliable means for calculating stranded cost.

Q. FAILING FULL DIVESTITURE, ARE THERE OTHER MEASURES THAT CAN BE ADOPTED THAT WILL MITIGATE MARKET POWER?

A. Yes. The Commission could order a partial divestiture, in which the APS reduces its market share in the Phoenix load pocket and Northern Arizona below the level at which it can exercise market power. We note that this exercise will require a thorough examination of the products produced by APS's various resources. For example, a partial divestiture would not mitigate market power if APS continued to own all of the load pocket resources needed to provide ancillary services in Northern Arizona or the Phoenix load pocket.

Market power may also be mitigated if APS is required to sell or exchange the output of load pocket resources with other unrelated entities. Under such a measure, APS would continue to own generation resources but would commit the output of those resources to unrelated entities in exchange for an equal amount of

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concerns with the potential for market power by the purchaser of a generation bundle that included Sunrise/Sunpeak facilities.

output from a generating resource in, *e.g.*, California or the Pacific Northwest. Such a measure could reduce APS's effective market share in the load pocket and Northern Arizona without effecting ownership. We note that control over the output would have to rest with the non-APS entity for this measure to mitigate market power.

Q. WHAT OTHER MITIGATION MEASURES SHOULD BE IMPOSED ON APS AND THE APS GENERATION AFFILIATE?

A. We urge the Commission to impose a requirement for a wholesale "recourse tariff" on APS as a condition of the settlement in the event that resource divestiture is not pursued. The wholesale recourse tariff should consist of three key elements. The first element should be a price cap with no true-up or cost adjustment clause for power sold in the load pocket by APS or APS-affiliate owned resources. This will shift some risk from rate payers to generators who should have the right economic incentives to manage its costs. The remaining components should be provisions allowing any potential purchaser to call on APS to provide power within the load pocket and Northern Arizona; and a price cap for ancillary services sold by APS or APS-affiliate owned generation. The wholesale recourse tariff would be filed by APS for approval with the Federal Energy Regulatory Commission.

The wholesale recourse tariff should not apply to new generation built within the load pocket or in Northern Arizona by non-Pinnacle West companies. Further, the recourse tariff should not apply once the Phoenix area load pocket is eliminated and its found that Pinnacle West companies can no longer exercise market power in Northern Arizona.

Q. HAS A RECOURSE TARIFF BEEN DISCUSSED AS A MITIGATION MEASURE IN ANY OTHER STATE?

A. Yes. Stakeholders in Nevada have agreed to impose a recourse tariff, titled a "Generation Aggregation Tariff" (GAT) in both Northern and Southern Nevada. Sierra Pacific Power Company recently filed such a tariff with FERC in Docket No. ER99-2332.

In its FERC filing, Sierra proposed different cost-based prices for each of the bundles it intends to auction in its asset divestiture. Sierra recently agreed in PUCN Docket No. 98-7023 to seek a change to the cost-based cap included in its FERC filing. After FERC approval of the cost-based cap, Sierra will seek FERC approval of an indexed pricing mechanism that will cap the hourly price available in Northern Nevada at the sum of the hourly of the Northern California Power Exchange price plus a capacity proxy value. The Northern Nevada market is limited by insufficient transfer capability both into and out of the load pocket. The indexed pricing methodology has been developed for the express purpose of encouraging new generation and transmission construction. Exhibit TED-2 is the indexed GAT accepted in Docket No. 98-7023.

Q. DO YOU SUPPORT THE PROVISION OF THE SETTLEMENT REQUIRING APS TO PARTICIPATE IN THE ARIZONA ISA?

A. Yes, they should be required to participate in the Arizona ISA (AISA), and a Regional Transmission Organization like Desert STAR once it is established. It is troubling to note that APS is not on the AISA board and only retains a simple membership status.

Q. IS THIS REQUIREMENT SUFFICIENT TO MITIGATE THE MARKET POWER THAT THE APS GENERATING AFFILIATE WILL HAVE?

A. No. The AISA and some of its protocols enhance the problem of market domination, and the AISA fosters an illusion that it shall be capable of patrolling and controlling such abuses.

Q. PLEASE EXPLAIN

R. FERC has clearly stated in its NOPR that

> "A retail choice initiative, no matter how well designed at the state level, may fail if the pool of potential competitors is effectively limited to a few nearby supply sources because of pancaked transmission charges. Utilities that control monopoly transmission facilities and also have power-marketing interests have poor incentives to provide equal quality transmission service to their power marketing competitors. It is, in fact, in the economic self-interest of transmission-owning utilities to favor their own power marketing interests and frustrate their competitors. This, in turn, can result in concentrated electricity markets."

The "poor incentives" FERC talks about were evident from the beginning of the AISA negotiations. APS has had no incentive to create an AISA that would level the playing field. APS has been unwilling to create an organization that removed the business decision access making functions to the AISA. The AISA now has limited oversight responsibilities, rather than "authority"; and the AISA will be a compliance monitor rather than an implementer. FERC has been quick to point out that this kind of ISA is unacceptable. FERC stated in its NOPR that;

> "An organization like an independent scheduling administrator that simply monitors the scheduling decisions of current transmission owners and offers dispute resolution services in case of a dispute would not qualify as an RTO. Similarly, a transmission organization that offers service under another entity's tariff would not meet this standard."

AISA's protocols are tilted toward the incumbents and help them further their generation market power and merchant positions.

Q. CAN THE AISA RESOLVE MARKET POWER AND COMPETITIVE CONCERNS THROUGH OVERSIGHT?

R. No. The AISA has little effective ***independence*** because it lacks authority to implement, does not schedule and has nothing to administer. Further, it is under funded and under staffed. It will be virtually impossible for this organization to either monitor utilities for compliance or enforce compliance. FERC stated in its NOPR that:

> "It is often hard to determine, on an after-the-fact basis, whether an action was motivated by an intent to favor affiliates or simply resulted from the need to serve native load customers or the impartial application of operating or technical requirements...perhaps the most problematic aspect of relying on after-the-fact enforcement in the fast-paced business of power marketing, however, is that there may be no adequate remedy for lost short-term sale opportunities."

Q. **WHAT ARE OTHER CONCERNS DO YOU HAVE WITH THE ISA ?**

A. **We have a number of concerns as follows:**

1) OASIS, Total Transfer Capability calculations (TTC), and Available Transfer Capability ATC: In the beginning, parties agreed that the AISA should be the place where all schedules would be submitted, ATC would be calculated and ATC would be posted on a state-wide OASIS. However, APS has backed away from this concept. A competitive market is dependent on the timeliness and accuracy of OASIS. ATC and OASIS have become vehicles for obstructing and curtailing, rather than accommodating, transactions. If the AISA is only copied on retail schedules and APS retains control of the OASIS and ATC, they will be able to deny new entrants access to critical, accurate information across control areas. The AISA can not do its job (e.g., know about Committed Uses and ATC) if it doesn't know about ***all*** schedules before hand. The AISA should be in control of the scheduling process to ensure that the incumbents, such as APS, do not unnecessarily reject schedules, post out-of-date or incorrect ATC or intentionally withhold ATC.

The current configuration of the AISA means that access to the grid remains in the hands of the incumbents and it will be in their interest to give their merchant a better quality service through various means. This will have the effect of enhancing merchant generation market power.

2) **Transmission rights:** Rights are allocated on a load's prorata share of the system, but APS has not conceded that this includes all of its contractual rights such as the Glen Canyon - Phoenix area line which APS currently uses to serve retail load. In effect, APS continues to withhold lines that benefit its own self-interests over its competitors.

The "prorata" concept is likely to give the incumbent another competitive advantage. If an APS customer goes with a new energy service provider, they will receive their prorata share of APS's entire system. To close a particular transaction, however, the customer will have to buy a slice of generation on every line on which it received a prorata share. The customer will not be able to purchase generation from its preferred supplier unless it rebundles transmission by "swapping" or "trading" its rights. However, the APS merchant holds 100 percent of all rights and APS will be capable of frustrating competition in such an ill-liquid market by just saying "no" to such swaps or trades.

3) **Multiple tariffs administered by the incumbent utility:** Administration of the tariff entails a multitude of judgments that require discretion, as well as "technical" judgments that have significant competitive ramifications. The AISA should be in charge of a statewide tariff, but it will not be. Without a statewide tariff and AISA control these decisions and judgments will be made by the transmission owners such as APS with competitive generation concerns in mind.

4) **Energy imbalance.** We are concerned with the imbalance protocol as well. The bundled merchant will never have an imbalance between its schedule and actual energy consumed by its load because the merchant is deemed to always have a perfect, balanced, schedule.

Further, the charges for small imbalances are unfair. If a Scheduling Coordinator (SC) has a small excess of energy, the Transmission Owner's (TO) merchant gets to buy it at the *lower of* System Incremental Cost. But if a SC has a small shortage, the TO's merchant sells to the SC at the *higher of* SIC or Market. Small imbalances should be bought and sold at the same price!

5) Must-run Counter Scheduling. Under the AISA protocols only must-run generators can create counter schedules or "net" schedules. These units are owned by the incumbents, and will not be available at capped rates when market power is prevalent in load pockets such as Phoenix and Tucson. Instead they will be fetching market prices at Palo Verde, rather than performing its must offer function to all merchants. This will further erode any shopping credit that is offered for competitive markets by enhancing localized generation.

6) Ancillary Services. An SC's Spinning Reserve and Non-Spinning Reserve obligations will not be reduced by any firm purchases (i.e., firm imports). This is discriminatory and will further enhance a concentrated generation market. Everyone but the incumbents will have to rely on imports. Non-incumbents will pay a price for firm imports such as the California PX, which does not sell non-firm energy. However, the TO's will not give a credit for such firmness, but will acquire the firmness value for their own generators. This will only further enhance the incumbent's generation position by concentrating such markets through the exclusion of others.

Q. HOW DO YOU SUGGEST CORRECTING THE PROBLEMS WITH THE ARIZONA ISA?

A. **AISA Authority** - First, the utilities should support an amendment to the AISA bylaws that give the AISA director clear authority and responsibility for upholding the integrity of its tariff.

State Wide tariff - Next, the AISA should be in charge of a single statewide tariff, and the utilities retail and wholesale OATT's should defer to the AISA's protocols and responsibilities. This means that the utilities OATT's can not be inconsistent nor supersede the AISA tariff.

OASIS, Total Transfer Capability calculations (TTC), and ATC – Third, OASIS, TTC and ATC must be under the control of the AISA rather than the incumbents. This shift of responsibilities can be achieved at reasonable cost. For example, the personnel at the various utilities today could receive their paychecks from the AISA. They would still work in and use current utility facilities but they would be employed by the AISA.

Transmission rights – Fourth, transmission right allocation should be done in a manner similar to the Nevada ISA, Desert STAR, and California approaches, *i.e.*, through an auction process.

Energy Imbalances – should be the same for the utility merchant as it is for its competitors. They should submit forecasts and schedules like everybody else, and should be subject to the same imbalance charges and penalties as their competitors. Further, small imbalances should be bought and sold at the same price.

Counter Scheduling – In addition, counter scheduling or "net scheduling" should not be limited to the incumbents must-run, and must-offer resources. Everyone should be allowed to "net schedule". Utilities should not be the only beneficiary of such an advantageous practice.

Ancillary Services – Firm imports should be given a credit for firmness -- instead of allowing the utilities to "pocket" the value of this firmness for their own generators.

Q. IF THE COMMISSION REQUIRES APS TO SUPPORT THESE CHANGES TO THE ISA AS A CONDITION OF APPROVING THE SETTLEMENT AGREEMENT, WILL THAT BE SUFFICIENT TO ADDRESS YOUR CONCERNS WITH MARKET POWER?

A. It would help but not resolve the larger problem. Even after the AISA is repaired, additional measures are necessary to mitigate horizontal market power.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

Docket Nos. E-01345A-98-0473
E-01345A-97-0773
RE-00000C-94-165

Supplemental Responses of Enron Corp. to
Arizona Public Service Company's Second Data Request #2

2. **Please indicate whether Enron is presently serving end-user customers in each of the jurisdictions listed above and the approximate number of such customers.**

Supplemental Response:

Without waiving any prior objections, Enron attaches copies of two reports filed with the United States Department of Energy which list the number of retail electric customers that Enron served for the time period noted on the reports.

EXHIBIT
Admitted
APS-5

U.S. Department of Energy
Energy Information Administration
Form EIA-826 (1999)

Monthly Electric Utility Sales and Revenue
Report with State Distributions - 1999

Form Approved
OMB NO. 1905-0129
(Expires 12-31-2001)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-70, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, call Parnese Goss at (202) 426-1217 or FAX phone (202) 426-0003 or contact the Survey Manager, Deborah Bolden at (202) 426-1235 or by E-Mail at: dbolden@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. Return completed form by FAX to (202) 426-0003; or mail to: U.S. Department of Energy, Energy Information Administration, EI-53, Mail Stop: BG-076(EIA-826) 1000 Independence Avenue SW, Washington, DC 20077-5651

Utility Name: Enron Energy Services
Attn: Office Manager
1400 Smith Street
Houston, TX 77002

Identification Code (Assigned by EIA): ID Code: 05787
Reporting for the month of: March 1999

Contact Person Karen Cordova Phone number: (713) 853 - 3150

ELECTRIC ENERGY INFORMATION ON SALES TO ULTIMATE CONSUMERS FOR SELECTED STATES

State	Items	Residential	Commercial	Industrial	Other	Total
CA	a. Revenue (thousand dollars)	442	8,118			
	b. Megwatthours	16,416	303,956			
	c. Number of consumers	26,265	9,830			
PA	a. Revenue (thousands dollars)		60			
	b. Megawatthours		1,205			
	c. Number of consumers		13			
RI	a. Revenue (thousand dollars)			57		
	b. Megawatthours			1,796		
	c. Number of consumers			1		
	a. Revenue (thousand dollars)					
	b. Megawatthours					
	c. Number of consumers					
	a. Revenue (thousand dollars)					
	b. Megawatthours					
	c. Number of consumers					
	a. Revenue (thousand dollars)					
	b. Megawatthours					
	c. Number of consumers					

NOTE:

BEFORE THE

ARIZONA CORPORATION COMMISSION

DOCKET NOS. E-01345A-98-0473

E-01345A-97-0773

RE-00000C-94-0165

TESTIMONY OF HARRY J. KINGERSKI

On Behalf of

ENRON CORP. AND ITS SUBSIDIARIES,

ENRON ENERGY SERVICES, INC. AND ENRON CAPITAL & TRADE RESOURCES

June 30, 1999

EXHIBIT

Admitted

Enron-6

DIRECT TESTIMONY OF HARRY J. KINGERSKI

Q. Please state your name and business address.

A. My name is Harry J. Kingerski. My business address is Enron Corporation ("Enron Corp."), 1400 Smith Street, Houston, Texas 77002.

Q. Where are you employed and in what position?

A. I have been employed with Enron since 1996. I am currently Director of the Rates/Regulatory group in the State Government/Federal Regulatory Affairs department of Enron Corp.

OVERVIEW OF ENRON TESTIMONY

Q. What is Enron's position on the proposed settlement reached on May 14, 1999 between Arizona Public Service and various other parties?

A. Enron believes there are significant issues that must be addressed and resolved before the Arizona Corporation Commission (Commission) approves the settlement Arizona Public Service (APS) settlement. The Commission should not approve the settlement before: (1) each of these issues is addressed through the imposition of conditions suggested by Enron witnesses Dr. Alan Rosenberg, Dr. Mark Frankena, and Mr. Thomas Delaney; and (2) the settlement is modified to resolve the issues raised in this testimony.

Q. Please summarize the testimony of Enron's witnesses in this proceeding.

A. Enron is sponsoring the testimony of three witnesses in addition to my own testimony. These witnesses are: Dr. Rosenberg, Mr. Delaney, and Dr. Frankena.

The settlement calls for APS to transfer certain generation-related assets to an unregulated affiliate but does not describe the terms under which the transfer will occur. Dr. Rosenberg describes issues related to the transfer of APS' generating and generation-related assets to an APS unregulated affiliate. Dr. Rosenberg suggests a number of key conditions the Commission should impose before approving the settlement. Dr. Rosenberg testifies that if tax, valuation, stranded cost, and capitalization issues are not addressed, the settlement will impair the development of a competitive market in Arizona and will likely ~~to~~ lead to substantial customer harm. Dr. Rosenberg notes that APS' responses to Enron discovery have been less than responsive.

Once generation-related assets are transferred to the unregulated affiliate, the settlement allows the affiliate to sell power to APS at market-based rates. The testimony of Dr. Mark Frankena describes the market power possessed by APS' generation and why it, if left intact, will impair competition in Arizona.

The settlement presumes the operation of an effective and efficient wholesale market with an independent system administrator. Mr. Delaney's testimony addresses the mitigation measures that will be necessary to: (1) ensure that the transfer of generating and generation-related assets will not place the APS affiliate in a superior competitive position; and, (2) ensure that the APS affiliate does not exercise market power. Mr. Delaney discusses both Enron's primary recommendation—*viz.*, divestiture, and a number of other measures including: (1) partial divestiture; (2) contractual commitments to limit effective market share; (3) resource exchanges to limit effective market share; and (4) wholesale recourse tariffs.

Q. Please summarize your testimony.

A. The settlement does not contain provisions for unbundling of APS' rates between competitive and non-competitive services or an adequate Code of Conduct between the utility and its unregulated affiliates. My testimony will describe why these deficiencies impair development of a retail competitive market and expose customers to risk that should be borne by APS.

Q. Given its view on these issues, what does Enron seek from the Commission?

A. Enron requests that the Commission reject the settlement or withhold approval of the settlement until: (1) the tax, capitalization, valuation and other issues raised by Dr. Rosenberg are addressed through imposition of the conditions he suggests; (2) the settlement is modified in certain key areas such as unbundling and development of an appropriate shopping credit; and (3) certain market power mitigation conditions are imposed on APS. We also respectfully request that the Commission adopt the modifications to the settlement suggested by my testimony. Among these modifications, is the separation of competitive and non-competitive services for the pricing of Standard Offer and Direct Access services.

INTRODUCTION TO TESTIMONY OF HARRY J. KINGERSKI

Q. Please describe your educational background and business experience.

A. I have a Master of Arts degree in Economics from George Washington University, a Master of Administrative Sciences degree from John Hopkins University, and a Bachelor of Science degree in Mathematics from the University of Pittsburgh.

Prior to my employment with Enron, I was employed with Baltimore Gas and Electric for 16 years. During that period, I was a rate analyst, senior forecaster, rates supervisor, Acting Director – Rate Research and Special Contracts, and Electric Pricing Director. Prior to my current position with Enron Corp., I was Director of Rates and Tariffs and Director, East Desk Pricing for Enron Energy Services, Inc.

Q. What are your current responsibilities?

A. My work involves analyzing the rates, tariffs and related filings of various utilities across the country which are involved in restructuring or other proceedings involving access to retail electric markets and the provision of services to retail electric customers.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Enron Corp. and its subsidiaries, Enron Energy Services, Inc. and Enron Capital & Trade (collectively, "Enron"). Enron is a leading provider of natural gas and electric power in both wholesale and retail markets in the United States and offers a broad range of products, capital, technology and related service capabilities, and energy asset management.

Q. Have you testified previously in other states regarding restructuring issues?

A. Yes. I have previously testified in restructuring proceedings in New Jersey, Pennsylvania, Illinois and Nevada on various restructuring issues, such as rate unbundling, default service and competitive pricing.

Q. What is the specific focus of your testimony and how is the testimony organized?

A. The focus of this testimony is on shortcomings in the APS proposed settlement of May 14, 1999 concerning APS' Standard Offer, Direct Access schedules, and Code of Conduct. The testimony is organized into the following four sections: (1) why Enron believes the settlement does not create the competitive framework envisioned by the Commission; (2) why the proposed pricing structure creates a competitive advantage for APS and a competitive disadvantage for third party electric service providers (ESPs); (3) a comparison and contrast of APS' proposed pricing structure for Direct Access with that being utilized in other states; and (4) why the Code of Conduct provisions of the settlement are unacceptable.

I. THE PROPOSED SETTLEMENT DOES NOT CREATE THE COMPETITIVE FRAMEWORK ENVISIONED IN THE COMMISSION'S ORDER NO. 61634.

Q. What is the Commission's mandate for competition?

A. The Commission's Order No. 61634 of April 23, 1999 specifically states its intent to be "to bring the benefits of electric competition to the citizens of Arizona as quickly as possible" (see p. 2, line 23). It is my understanding and impression that the Commission has been proactive and a leading proponent in bringing electric competition to Arizona consumers.

Q. Will APS' proposed settlement accomplish the Commission's purpose of bringing the benefits of electric competition to the citizens of Arizona as quickly as possible?

A. No, I do not believe it will. APS mistakenly equates "retail access" with "bringing the benefits of electric competition to the citizens of Arizona as quickly as possible." The two are not the same. As I understand it, the Settlement advances the date of 100% complete retail access to January 1, 2001 and increases the non-residential load eligible for access in the first phase by 140 MW. Indeed, Mr. Davis of APS lists "the accelerated introduction of retail electric competition in the APS service area" as the first primary benefit from the settlement agreement (see p. 13, line 7). Dr. Landon further lauds the benefits to competition from advancing the date for market opening: "The Agreement has numerous pro-competitive aspects. It ushers in consumer choice very rapidly by beginning open access immediately upon approval and upon enactment of the Electric Competition Rules and by allowing for full open access within two years." (See p. 7, line 22).

Q. Why is "opening the market" not synonymous with achieving the "benefits of electric competition"?

A. Effective retail competition and the resulting benefits will be achieved only if electric service providers (ESPs) have a fair opportunity to compete with the incumbent utility on terms that allow the ESP to recover its costs. APS' proposed settlement does not create this opportunity. As the settlement is now structured, I believe that ESPs may not enter the APS market, because they will be unable to do so profitably. If they do not enter the market, effective retail competition will not be achieved and the benefits of competition will not accrue to the citizens of Arizona. Advancing the date of market opening means nothing if competition is unlikely to develop when the market opens. In my opinion, that would be the net result under the settlement agreement in its present form.

Q. Why is APS' Standard Offer Service in competition with the offerings of ESPs?

A. The Standard Offer should be a primary benchmark for customers who are evaluating a decision to switch to an ESP. A customer will compare the Standard Offer against the ESP's offerings when deciding whether to switch suppliers. The format of the Standard Offer should promote this type of comparison shopping. Per the Commission's Order No. 61634 (see Appendix A, R14-2-1606, subsection C), tariffs for the Standard Offer are required to include the following elements:

a. Electricity:
   (1) Generation
   (2) Competition Transition Charge
   (3) Must-Run Generating Units
b. Delivery
   (1) Distribution Services
   (2) Transmission Services
   (3) Ancillary Services
c. Other
   (1) Metering Service
   (2) Meter Reading Service
   (3) Billing and Collection
d. System Benefits

These are essentially the same bundle of products, at a minimum, that an ESP must bundle together to serve a customer. Customers and ESPs have a need to know the prices for these service components of the Standard Offer rate.

Q. What do you mean when you state that electric service providers need a fair opportunity to compete with the incumbent utility?

A. Because an electric service provider must compete with the APS' standard offer, the provisions and pricing of the Standard Offer must be fair or "competitively neutral" between APS and electric service providers. By "competitively neutral," I mean that an ESP that is equally efficient with APS in providing retail service can provide equivalent service at the same cost. In this case, the ESP should not be at a competitive advantage or disadvantage with APS because of the way Standard Offer service is priced. An ESP that is not as efficient as APS in providing retail service should be at a competitive disadvantage; conversely, an ESP that is more efficient than APS at providing retail service should have a competitive advantage against APS' Standard Offer.

Q. Does the settlement permit fair competition between APS' Standard Offer and electric service providers?

A. No. For reasons I discuss in this testimony, the settlement gives APS a competitive advantage against ESPs even if the ESPS are as or more efficient than APS in providing retail services.

Q. Will the source of generation for APS' Standard Offer and the offerings of ESPs be similar?

A. In theory, yes. Order No. 61634 requires "after January 1, 2001, power purchased by an investor owned Utility Distribution Company to provide Standard Offer Service shall be acquired through the open market." (See R14-2-1606, subsection B.) ESPs will acquire the majority of their electric generation on the open wholesale market as well.

Q. Does the settlement reflect the Commission's desires with respect to this requirement that Standard Offer Service be supplied through open market purchases?

A. No, I do not believe so. The settlement is unclear as to both the source of supply APS will use for Standard Offer Service and the risk APS is subject to in providing the service. The Commission was very clear in its intent on this issue. Appendix C, p. 30, to Order No. 61634 states "the Commission wants to send a clear message to UDCs that whenever possible, it will be more preferable and desirable to find the lowest-cost generation sources and mix available than to seek a rate increase to pay for higher-cost generation for Standard Offer Service customers." This mandate to find the lowest cost of generation supply is not reflected in the settlement. In fact, a reader of the settlement could conclude that the costs of Standard Offer Service are completely recoverable from all customers receiving services from APS, with no risk to APS and regardless of the prudence of APS' purchasing practices. (See, for example, settlement section 2.6, paragraph (3); section 2.6, last sentence "APS shall be allowed to defer costs covered by this section 2.6 when incurred for later full recovery pursuant to such adjustment clause or clauses, including a reasonable return."; and section 2.8).

Q. Why is it important to Enron that APS in fact bear this risk?

A. As I have stated previously, Enron and other ESPs will offer a product which is a competitive alternative to the Standard Offer. ESPs bear risk in their product offering. It is not in the interests of competition to have one competitor – APS – escape normal competitive market risks through regulatory loopholes in the settlement. It is possible that the price for the Standard Offer could be below cost, precluding competition for a period of time, and then APS could seek to recover those losses through an adjustment clause in a later period. This outcome, if it develops, meets the classic definition of predatory pricing.

Q. Does the proposed settlement allow APS to engage in predatory pricing ?

A. I believe the answer is, yes, it does. My belief is based on the ambiguity in the settlement and on APS' responses to Enron's data requests. For example, in data request #3, question 2c, Enron asked:

> q. Are APS' shareholders at risk for any revenue shortfalls incurred between July 1, 1999 to June 30, 2000 from providing energy commodity service as the provider of last resort? For the period from June 30, 2000 through 2004?

APS replied:

> a. APS will only become "provider of last resort" ("PLR") within the meaning of Article II, Section 2.6 upon final approval of the ACC's electric competition rules and only then if that final version of the rules imposes that obligation upon APS. These preconditions may never occur or may not occur until after July 1, 1999. With that understanding, APS shareholders will be at risk for any increased energy commodity costs attributable to the Company's PLR or Standard Offer Service ("SOS") prior to July 1, 2004, with the following provisos:
>
> > i. Some or all of any such increased costs may be reflected in the test period used for the rate filing referenced in Section 2.7:

ii. Higher energy commodity costs attributable to customers that have left to a competitive supplier and thereafter returned to SOS prior to July 1, 2004 are recoverable under Section 2.6 (2); and,

iii. The ACC could permit recovery of such costs under the emergency provisions of Section 2.8.

Clearly, provisos i and iii capture the predatory pricing possibility. Under the scenario where market prices spike upward, and Standard Offer price remains fixed, APS retains the right to seek recovery of those increased costs from all customers at a later point in time.

Q. How does APS' recovery of stranded costs relate to its competitive advantage in to the Standard Offer?

A. Under the terms of the settlement, APS will be compensated $350 million for stranded costs. It makes no sense to compensate the utility $350 million for stranded costs and then turn around and further reward APS with a rate increase if market prices increase above expected levels. In his direct testimony on behalf of Enron, Dr. Rosenberg gives additional reasons for Enron's objections to this part of the settlement.

Q. What remedy do you recommend?

A. At a minimum, the Commission should direct APS to modify section 2.6 and 2.8 of the settlement to clearly reflect the Commission's intent in Order No. 61634, stated above, that it will not tolerate a rate increase for Standard Offer customers because of any upward movement in market prices. Preferred remedies for the settlement, in general, are described in Dr. Rosenberg's testimony.

Q. You mentioned earlier that the Standard Offer should be a primary benchmark for customers who are evaluating a decision to switch to an ESP.

Does the Settlement clearly identify the components of the Standard Offer as required in Order No. 61634?

A. No. Under the proposed settlement, the Standard Offer will consist of APS' current bundled rate schedules, adjusted for the rate reductions described in section 2.2 of the settlement. This format for Standard Offer does not comply with the Commission's directive to include and identify the 10 components noted above (electricity, delivery, other, system benefits, etc) in the Standard Offer.

Q. Is this simply a format issue?

A. No. In order for competition to develop in Arizona, it is critical that APS comply with the Commission's decision in this regard to show and separately price in a tariff the minimum components of Standard Offer Service listed in Appendix A of the Order. This price transparency is important to customers for shopping purposes and is important to ESPs to ensure service comparability.

Q. Has the Commission given direction to utility companies as to how the separate elements of Standard Offer Service should be priced?

A. Yes. The Commission requires that "such rates shall reflect the costs of providing the service." (See Order No. 61634, Appendix A, R14-2-1606, subsection C, paragraph 4). This requirement is parallel to the requirement that utilities' rates for unbundled services also "shall reflect the costs of providing the services." (See Order No. 61634, Appendix A, R14-2-1606, subsection H).

Q. In your view, why has the Commission adopted these "parallel requirements" for pricing Standard Offer Service and unbundled services?

A. I believe these parallel requirements for cost-based rates are specifically designed to allow a comparison between Standard Offer and ESP offerings and to avoid giving either the utility or its ESP competitors an advantage in the marketplace. The Commission wants the price for regulated services provided by utilities to be based on embedded costs. It also wants the service to be priced the same, regardless of whether the customer is purchasing the service directly from the utility under Standard Offer Service or whether the ESP is purchasing the service from the utility on behalf of its customers. These requirements are designed to create a level playing field on which fair competition can take place. For example, distribution service for an end-user is the same regardless of whether that customer is a Direct Access or Standard Offer customer. Accordingly, the distribution rate applicable to this customer for Standard Offer or Direct Access should be identical.

Q. Does the proposed settlement adopt these parallel pricing requirements whereby Standard Offer Service and unbundled services are priced comparably?

A. No. The Standard Offer tariff will not show cost-based rates for the various elements of Standard Offer Service if the tariff simply mimics existing bundled rate design. Customers will not know the price for individual services. Competing ESPs will not know if the price for distribution delivery service truly is the same regardless of whose electrons are flowing across the distribution system. Under the proposed settlement, bundled pricing of Standard Offer Service comes out of a "black box" with no further information made available to customers.

II. APS' PROPOSED PRICING STRUCTURE CREATES A COMPETITIVE ADVANTAGE FOR APS AND A COMPETITIVE DISADVANTAGE FOR ELECTRIC SERVICE PROVIDERS

Q. Why does the proposed pricing for Standard Offer Service and Direct Access under the settlement create a competitive disadvantage for ESPs?

A. APS' proposed pricing structure does not fully unbundle nor distinctly identify the separate components that comprise retail electric service. When an ESP engages in an activity that is part of the process of providing retail service, it incurs costs for that activity. Its ability to recover those costs in its price is critical to its business viability. APS has comparable activities and costs that largely remain in its pricing for Standard Offer Service or Direct Access delivery tariffs. However, APS is guaranteed recovery of costs for these activities regardless of whether the customer purchases from APS. APS' failure to perform the necessary unbundling will force the ESP to either absorb costs for services it does not use or seek what amounts to "double-recovery" from customers. In either event, ESPs are placed at a competitive disadvantage to APS' Standard Offer Service.

Q. What do you mean when you say customers will be subject to "double-recovery" from some services?

A. Double-recovery occurs where customers are forced to pay for the same service twice. This is a potential outcome if a customer purchases electricity from an ESP and the customer pays for some segment of the retail service twice – once to the ESP in the ESP's price for service, and once to APS through the regulated Direct Access tariff. For example, APS has billing and collection costs in its

Direct Access distribution rate for rendering a bill, answering questions about that bill, for having to possibly engage in collection activity for payment, and for possibly having to write-off the amount on the bill as a bad debt. For a customer served by an ESP, the ESP, not APS, provides these services and incurs the related costs. The customer is subject to paying for APS' billing and collection costs through the distribution rate that is billed by APS to the ESP, and through the ESP's charges. Thus there is double recovery, even though the service is provided only once. Service and cost unbundling could remedy this problem.

Q. Has APS used unbundled costs to determine its unbundled rates for Direct Access customers?

A. No. As Mr. Propper on behalf of APS has testified (see pps. 4-5), APS used an "apportionment process" to set rates rather than designing unbundled rates directly from a functional revenue requirement analysis. As reason for this, Mr. Propper states "there were two primary reasons: (1) revenue stability; and (2) rate continuity. It is APS' intent that the process of rate unbundling produce neither large revenue erosion due to rate migration nor customer dislocation due to reallocation of revenue requirements. By apportioning current bundled rates into functional charges that total to the bundled rate, appropriate revenue recovery is assured."

In other words, APS' only motivation in designing its Direct Access and Standard Offer rate structures is preservation of its revenue. Nowhere does APS indicate any intention to have unbundled rates reflect the cost of the unbundled service. Nor does APS indicate any consideration of the impact of its unbundling method on the development of a competitive market. In my opinion, this failure to recognize appropriate recovery of costs of service and competitive impact of bundled rates is a fatal flaw in APS' proposal.

Q. How should APS design its Direct Access and Standard Offer rates?

A. APS should unbundle retail services such that the prices for retail services add up to the total for the bundled product. For services that are competitive, such as commodity, metering or billing, the customer avoids the price of the competitive service if it is not purchased from APS. For services that are not competitive, such as distribution and transmission delivery, the customer should see the same price for the service, regardless of whether the total retail bundle is purchased from APS or portions of the bundle are purchased from an EPS.

Q. What are the specific retail activities for which APS should unbundle its costs?

A. At a minimum, APS should unbundle its retail costs into the ten categories listed by the Commission and noted above. I believe it is also necessary to unbundle additional generation-related functions related to commodity acquisition and supply portfolio management, energy imbalance costs, and planning reserves, and distribution-related functions related to metering, billing and customer handling.

For illustrative purposes, these categories have been depicted in Exhibit HJK-1 for both the Standard Offer retail product and the retail product sold by an ESP. The shaded areas, representing prices for non-competitive services, are the same in both cases. The competitive services, with no shading, are the services for which APS and ESPs are in competition. The key concepts to note from the

Exhibit are that (1) prices for non-competitive services should be competitively neutral; that is, they should not affect the customer's decision of where to purchase competitive services, and (2) the success of competitors should depend on their success at providing competitive services, and not on the pricing of non-competitive services.

Q. What are commodity acquisition and supply portfolio management costs?

A. When APS supplies standard offer service by buying at market, it (or an affiliate) has activities and costs relating to managing and obtaining the commodity supply. This includes personnel and related costs necessary for negotiating and executing contracts, scheduling power and forecasting load, and monitoring price movements and trading power. In essence, these are activities and costs related to maintaining a wholesale power supply function.

These costs are currently incurred by APS. An ESP has similar activities and costs to serve its customers. When a customer purchases from an ESP, the customer is exposed to double recovery of these costs if APS is recovering the costs of acquisition and portfolio management through its Direct Access rates. The Direct Access customer is in fact paying APS for a service it does not take.

Q. What are energy imbalance costs?

A. At the wholesale level, an energy imbalance is the difference between energy scheduled and energy delivered to the utility's transmission system. At the retail level, an energy imbalance is the difference between energy scheduled by an ESP or Scheduling Coordinator and the energy consumed or metered by the ESP's customers. Imbalances are inevitable because customers' usage fluctuates day-today, hour-to-hour, and moment-to-moment. It is highly unlikely that any energy provider, including APS when it supplies Standard Offer Service, will predict to 100% accuracy the actual amount of energy used by its customers. Through retail rates, APS recovers its wholesale costs for additional energy purchases or sales necessary to balance its energy supply with customers' needs.

APS currently has on file with the Federal Energy Regulatory Commission ("FERC") its Open Access Transmission Tariff ("OATT"). Within this OATT is its Energy Imbalance Service Schedule 4 ("Schedule 4"). Contained in Schedule 4 are the rates and terms and conditions for charging for energy imbalances at the wholesale level. It is not clear how APS will recover its costs for energy imbalances at the retail level. APS needs to unbundle this service, and its related charge, in its Standard Offer price.

An ESP will incur imbalance costs, just as APS will incur them when purchasing from the open market for Standard Offer Service. If this service component is not unbundled, an ESP's customers will pay this charge twice – once through APS' Direct Access rate and a second time to the customer's ESP. This obviously works to the competitive disadvantage of ESPs.

Further, the rules being developed for the AISA may have asymmetric rules regarding imbalances. Under the developing AISA Energy Imbalance Protocol, ESPs' scheduling coordinators will be compensated at system incremental cost for over-deliveries, but will have to pay the higher of system incremental costs or market for under-deliveries. These biases, if left intact, would advantage the Standard Offer if APS is not subject to the same balancing rules.

Q. What are planning reserve costs?

A. Planning reserve is a cost of providing energy at retail. It represents the generation capacity that utilities traditionally built, and Independent System Operators may require, in excess of expected load. This planning reserve margin is typically in the order of 18% of generation capacity. Planning reserve improves reliability by providing a margin of error for generation availability.

It is not clear at this time if APS (or AISA, in the future) will require ESPs to have a certain amount of planning reserves available in excess of contracted load. If a planning reserve requirement is imposed on ESPs, then planning reserve costs must be unbundled from the electric commodity function. The exact amount to be unbundled will depend on the nature of the planning reserve requirement.

Q. What are metering costs?

A. Metering costs are the capital and expense costs incurred to accurately meter the customer's usage. They include costs as recorded in FERC account 370 (Meters), 586 (Meter Expenses), 597 (Maintenance of Meters), 902 (Meter Reading).

APS has proposed to unbundle metering costs only to the extent of giving an "avoided cost" credit if the customer's ESP provides the meter and meter reading. (See testimony of APS witness Alan Propper, p. 15). The avoided cost credit is APS' attempt to measure the actual costs avoided by APS in the very short run if it does not provide the metering service.

This short run approach to measuring avoided cost is inappropriate for unbundling purposes. It creates the perverse impact of encouraging an ESP to use APS's metering, even if the ESP has a more efficient or value enhancing metering process. The ESP must overcome the built-in subsidy to APS' metering, which equals the difference between APS' embedded metering cost and its measurement of avoided cost. The embedded metering cost is the actual cost included in APS' rates for metering. In other words, the ESP must provide increased efficiency or value added service equal to the subsidy just to break even with the APS option. In addition, ESPs may face asymmetric metering requirements that require hourly interval meters for direct access customers, necessitating a new meter, whereas the Standard Offer customer is allowed to use the existing meter.

The Commission should direct APS to unbundle its metering costs and give an embedded cost credit when the ESP provides metering services.

Q. What are billing and collection costs?

A. Billing and collection costs are for activities that include providing information, advertising, customer relations, collections and bad debt write-offs, physical rendering of the bill, sales and advertising. In Exhibit HJK-1, this category is referred to as "MBC"; meter, bill and customer handling. These costs generally are included in FERC accounts 901 through 917; billing costs in particular are included in account 903. The ESPs will have their own sales cost, the customer relations expense, and the uncollectible expense associated with its customers. Customers should not have to pay twice – once to APS and once to the ESPs – for these services.

The Commission should direct APS to unbundle its billing and collection metering costs and give an embedded cost credit when the ESP provides these services.

Q. Is there evidence that APS' proposed rate structure will result in the type of double recovery of costs that you have suggested is possible?

A. Yes. Exhibit HJK-2 provides a hypothetical, but realistic comparison of the delivered cost of energy provided by an ESP with APS' Standard Offer for both a medium-sized (500 kW) and large (3 mW) direct access customer. For the chosen hypothetical customers, the calculations show an ESP can not compete with APS' Standard Offer, even though both offers start with the same market value for generation.

Q. Please explain the calculations contained in Exhibit HJK-2.

A. The cost of power from the ESP starts with the wholesale price as measured by the NYMEX futures price for Palo Verde (column 1). The NYMEX Palo Verde wholesale price is for on-peak periods, 16 hours a day for the 5 weekdays, excluding holidays. There is no comparable off-peak price for Palo Verde. The NYMEX wholesale price is weighted with an estimate for off-peak prices which uses a relationship between on and off-peak prices for the California PX to derive an overall Palo Verde wholesale value.

The wholesale price represents a 100% load factor rate because wholesale loads are typically purchased in 100% load factor blocks. Of course, the retail customer typically has a load factor less than 100%, with a concentration of load during the day. Column 2 adjusts the wholesale price for a retail load profile.

Column 3 shows an adjustment for line losses. Column 4 shows the total commodity cost; this is the "ESP Market Generation" component of the Direct Access customer's cost depicted in Exhibit HJK-1.

Columns 5 through 10 depict the charges for services to bring the wholesale power to the customer's meter. There are charges for distribution and transmission delivery, ancillary services, CTC System Benefits, and a Variable Must-Run Generation Charge. Rates from the applicable Direct Access schedule and expected modified Open Access Transmission Tariff not yet filed at FERC are used to determine these prices. Column 11 shows the total delivered price to the customer. Keep in mind that this total delivered price includes all of the shaded components depicted in Exhibit HJK-1 plus the ESP Market Generation; it does not include the costs the ESP incurs for planning reserves, ESP imbalances, ESP commodity acquisition, and ESP meter, bill and customer handling.

Column 12 shows the customer's applicable price under the comparable APS Standard Offer schedule, E-32 and E-34, for the two customers, respectively. The implied shopping credit, Column 13, is the amount remaining after the utility's direct access charges (columns 5-10) are deducted from the Standard Offer price. In effect, the implied shopping credit is the price for competitive services the ESP must beat if it is to beat the Standard Offer price. In both cases, the shopping credit on an annual basis is about equal to the ESP's total commodity price, even with no recognition in the commodity price for ESP planning reserves, ESP imbalances, ESP commodity acquisition cost, ESP meter, bill and customer handling costs, profit, and savings to the customer.

Q. What do you conclude from this analysis?

A. An ESP can not compete for these two customers of typical size and load shape and come anywhere close to recovering its out of pocket costs, let alone earn a profit. From this analysis, I think two conclusions are reasonable. First, competition will not develop in APS' service territory, as the Commission intends, because ESPs will not enter a market and incur market start-up costs if there is no prospect for fair competition or reasonable margins. Second, double recovery of certain costs appears to be occurring under APS' rate structure. In other words, at least some of the costs for Standard Offer services designated as competitive in Exhibit HJK-1 appear to be included in delivery charges. This conclusion assumes there is no material difference between the cost of open market purchases incurred by APS to supply Standard Offer and the cost of open market purchases incurred by ESPs to supply a Direct Access customer.

Q. Is it appropriate to assume the Standard Offer and ESP market prices are the same?

A. Yes, I believe so. The 100% load factor price for Palo Verde used in Exhibit HJK-2 is nearly identical to the market revenue price used by APS in its stranded cost estimate. (See APS exhibit JED-3). In principle, they should be the same. As noted earlier, the Commission has directed the company to have the generation component of Standard Offer Service reflect open market purchases. If the generation component of Standard Offer Service is under the market value, then Standard Offer Service is being subsidized and the subsidy should be eliminated. Alternatively, if this is a subsidy and the subsidy is not eliminated, then ESPs should have the same right to purchase energy from APS at the same below-market price as contained in the Standard Offer.

Q. Have you performed an additional analysis to support your contention that pricing for Standard Offer Service gives a competitive advantage to APS?

A. Yes. Exhibit HJK-3 shows for a Schedule E-32 and E-34 customer how the price for marginal consumption under the Standard Offer compares to the market price of energy. The declining block structure of this existing rate schedule results in a situation where increased usage, absent an increase in demand, is typically priced lower than the wholesale market price of energy plus delivery. In other words, the total bundled price from APS for incremental purchases of energy does not even recover the wholesale cost of energy plus delivery. Clearly it is impossible for an ESP to compete against such flagrant below-cost pricing.

Q. What are your recommendations to the Commission?

A. The Commission should reject the proposed settlement until it has been redesigned to allow meaningful competition to take place. APS should be required to perform the service and cost unbundling described in this testimony. This will allow customers to make meaningful comparisons of ESP offers to the Standard Offer and prevent the double recovery of costs by APS.

An alternative, interim solution to unbundling would be for the Commission to (1) accept Dr. Rosenberg's observation that the level of stranded costs in the settlement is excessive, (2) reduce the CTC rates and thereby increase the shopping credit, and (3) set a specific schedule for accomplishing the unbundling objectives described in this testimony.

III. THE EXPERIENCE OF OTHER STATES CONFIRMS THAT ADJUSTMENTS RECOMMENDED BY ENRON ARE NECESSARY FOR A COMPETITIVE MARKET TO DEVELOP

Q. Does your experience in other states confirm your belief about the Commission's need to make the recommended adjustments?

A. Yes. In particular, I would cite the experience of the New Jersey and Pennsylvania commissions in promoting competition through the use of appropriate unbundling and use of adjustments to recognize costs inherent in a retail market.

Q. What has been the practice in New Jersey to develop "shopping credits"?

A. The New Jersey Legislature passed The Electric Discount and Energy Competition Act (the "New Jersey Deregulation Act") on February 9, 1999 which opened the New Jersey retail market for competition effective no later than August 1, 1999. The legislation directed the New Jersey utilities to provide "shopping credits applicable to the bills of their retail customers who choose to purchase electric generation service from a duly licensed electric power supplier". (New Jersey Deregulation Act at § 4.) The shopping credits were to further the Legislature's goals to:

- "(1) Lower the current high cost of energy, and improve the quality of choices of service, for all of this state's residential, business and institutional consumers ...;

- "(2) Place greater reliance on competitive markets, where such markets exist, to deliver energy services to consumers in greater variety and at lower cost than traditional, bundled public utility service"; and
- "(7) Provide diversity in the supply of electric power throughout the State".

(*Id.* at § 2.) Public Service Company of New Jersey, the state's largest utility, reached a restructuring agreement which the Board of Public Utilities (BPU) approved April 21, 1999. The Stipulation sets a shopping credit inclusive of an allowance for the cost of energy, capacity, transmission, ancillary services, losses, taxes and "retail adder". GPU Energy, another New Jersey utility, also reached a settlement, approved by the BPU May 19, 1999, in which the shopping credit is inclusive of an allowance for the costs of energy, capacity, transmission, ancillary services, losses and taxes, plus an "incentive" or "retail adder" in order to enable customers to shop. The GPU Stipulation specifies a retail adder of 1.10 cents per kWh for the year 2000; the PSEG Stipulation does not specify the individual components.

Q. What has been the practice in Pennsylvania to develop shopping credits?

A. The Pennsylvania Public Utility Commission has approved company-specific settlements that establish shopping credits which encourage consumer shopping for electricity. The Commission's landmark decision in this regard involved PECO Energy Company ("PECO"). On December 11, 1997, the Pennsylvania Commission directed PECO to establish shopping credits as the "difference between a particular customer's total rate as of January 1, 1997 and the sum of

T&D and CTC rates established pursuant to this order". (PECO Order at p. 42). By including in the shopping credit an increment to the wholesale power price, the Commission recognized that its approach "avoids creating a de facto monopoly that delivers temporary and short-term rate cuts. It creates real incentives for electric suppliers to compete for customers and for customers to shop for electricity. As such, this decision will create a market featuring both many buyers of electricity and many sellers of electricity." (*Id.* at p. 44).

The Pennsylvania experience to date shows the most activity in terms of customers shopping, switching, and achieving savings of any state open to competition. I expect New Jersey will provide similar evidence of competitive activity after the market opens.

Q. What should the Commission learn from the experience in New Jersey and Pennsylvania?

A. The Pennsylvania PUC and the New Jersey BPU desired to promote vibrant, welfare-enhancing competition over the long term. Customers are more interested in retail access when they are allowed to realize the benefits of competition. These commissions recognized that their state's legislative intent of promoting competition could only be achieved if consumers were given incentive to shop and competitive suppliers were given incentive to supply. These commissions acted within their legislative mandate to establish shopping credit rules that give competing suppliers the opportunity to compete fairly with incumbent utilities. The Pennsylvania experience to date with customer shopping, where over 400,000 or nearly 10% of eligible customers have switched suppliers, and the interest among suppliers to compete in New Jersey, are early signals of a vibrant market.

Q. Does the lack of customer switching in California present a contrast in impacts from different approaches to pricing energy?

A. Yes. In California, where only about 1% of eligible customers have switched suppliers, customers have shown little interest in shopping for competitive commodity supply. As has been well documented in other places, the California regulatory model does not create customer incentives for electricity shopping prior to the CTC roll off period. I believe this is at least partly because of the lack of opportunity presented to ESPs to deliver savings to customers and still receive recovery of their retail costs in competitive offerings. This is in contrast to the Pennsylvania and New Jersey regulatory models.

Q. Will there be any modifications to the California market structure that provides a more level playing field that may support competition?

A. Yes. The California Public Utilities Commission recently adopted Decision No. 99-06-058, dated June 10, 1999, requiring utilities to unbundle direct, indirect and overhead costs from distribution rates and include these back office and front office costs in their PX credits for direct access customers. In the discussion of that Decision, the CPUC states, "...to require direct access customers to assume costs for which they are not responsible may compromise efforts to promote competitive markets." (p. 23) California is now realizing the importance of comparability to competition and customer choice.

IV. THE CODE OF CONDUCT PROVISIONS OF THE SETTLEMENT ARE UNACCEPTABLE

Q. Does the Settlement raise concerns over transactions between APS and its affiliated companies?

A. Yes. Because the generation and other competitive assets are being transferred to affiliated entities, transactions between APS and its affiliates can be constructed and competitive information not generally available to the public can be shared between the companies, giving the affiliate energy service provider a tremendous, yet unearned, competitive advantage over third party energy service providers.

Q. Explain how the utility and its affiliate can engage in anti-competitive practices.

A. Unfair competitive practices arise when the utility uses information, personnel, access to facilities and services that are part of its monopoly structure to give it or its affiliate a competitive advantage in providing non-monopoly, or competitive, services in the marketplace. For example, the utility might give its affiliated ESP a customer list that was not in the public domain, give an affiliate preferential access to transmission or distribution service, or provide the affiliated ESP with marketing leads that the utility obtained through its position as monopoly utility.

Q. How can these abuses be prevented?

A. Protection against these types of activities comes in two forms: structure and rules. First, structurally separating the competitive and non-competitive services makes it more difficult for the utility and its affiliate to engage in these activities.

It also makes it easier to discover these activities. Second, rules prohibiting such activities and penalties for infractions of these rules act as a deterrent. These rules are generally contained in codes of conduct which specify certain activities that the utility cannot engage in and otherwise set standards of conduct for the utility to prevent undue preference to itself or its affiliated companies.

Q. Does the Settlement offer sufficient protection against affiliate preference or abuse?

A. No. The Settlement fails in both the structural and code of conduct areas. As to structure, I note that, for three ~~two~~ years after implementation of the Settlement, APS will not even transfer its generation assets to an affiliate. The competitive generation services will be provided by APS, the same company providing standard offer service and the monopoly transmission and distribution service, creating tremendous potential and incentive for unduly preferential treatment of deals involving APS-owned generation. Further, as Dr. Rosenberg notes in his testimony, APS has not yet developed a plan to create and fund an affiliate that will take ownership of the generation assets. This means we cannot evaluate whether the affiliate that ultimately owns the competitive assets will have adequate separation from APS to protect against cross-subsidization, information sharing or other unduly preferential activities.

Q. The APS Settlement provides for an Interim Code of Conduct to be adopted. Is this adequate protection?

A. No, for several reasons. The most obvious is that we have not seen the Interim Code of Conduct and have no assurances that it will address the panoply of issues that a comprehensive code of conduct, in our view, must address. In fact, it is to be filed only after the Commission has approved the settlement. Second is the fact that under section 7.7 of the Settlement, the Interim Code of Conduct is not, as its name implies, a permanent set of rules. The Settlement states that APS will comply with the Interim Code of Conduct until the Commission approves a Code of Conduct in accordance with the Commission's Electric Competition Rules.

Q. Why is this a problem?

A. Prior to the last round of changes to the Electric Competition Rules, Rule 14-2-1616 contained detailed proscriptions on certain activities by the utility that were to be incorporated into a code of conduct. These provisions were intended to prevent the utility from abusing or unfairly exerting market power. The rules required the utility and its marketing affiliates to operate as separate companies, with separate books and records. It prohibited the sharing of office space, equipment, services and systems and access to information and computer systems. The rules contained pricing, reporting and conduct rules for sharing certain corporate support functions, limited the affiliate's use of the utility's name and logo and restricted the sharing of advertising space, joint advertising, personnel, marketing and sales. Other provisions regulated the ability to transfer goods and services between the utility and the affiliated company, prohibited cross-subsidization and access to confidential information, set conditions for disseminating non-public consumer information and set requirements for documenting tariffed and non-tariffed transactions between affiliates.

The new version of the rule adopted by the Commission in April fails to specify what specific issues and activities the code of conduct shall address. The new rule simply states that each Affected Utility which plans to offer Noncompetitive Services and Competitive Services through its competitive electric affiliate shall propose a code of conduct to prevent anti-competitive activities. Without specific guidance as to what the rules must contain, we have no guarantee that the permanent code of conduct to be adopted by APS will offer anywhere near appropriate protections against undue preferences to its affiliate or undue discrimination against third party energy service providers.

Q. DO YOU HAVE A RECOMMENDATION CONCERNING THE STANDARD OF CONDUCT?

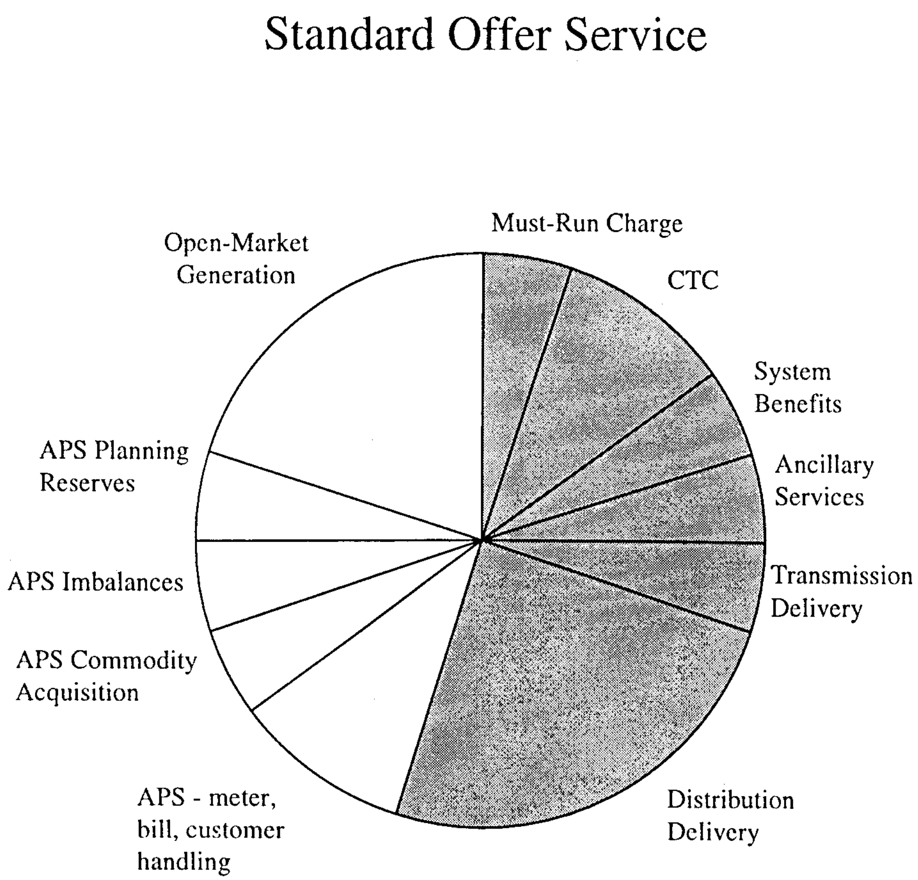
A. Yes. We urge the Commission to withhold approval of the settlement agreement until a satisfactory code of conduct has been developed and approved by the Commission. If the Commission intends to go forward with approval of the settlement, then we urge the Commission to impose a code of conduct that is identical to that adopted by the Nevada Public Utilities Commission (PUCN) in Docket No. 97-8001. The PUCN's code: (1) imposes rules that will require the Nevada "wires" company to treat any of its affiliates the same as any other competitive provider; (2) protects against cross-subsidization of regulated and unregulated activities; (3) prevents joint marketing activities between the affiliate and wires companies. A copy of this code of conduct is attached to my testimony as Exhibit HJK-4.[1]

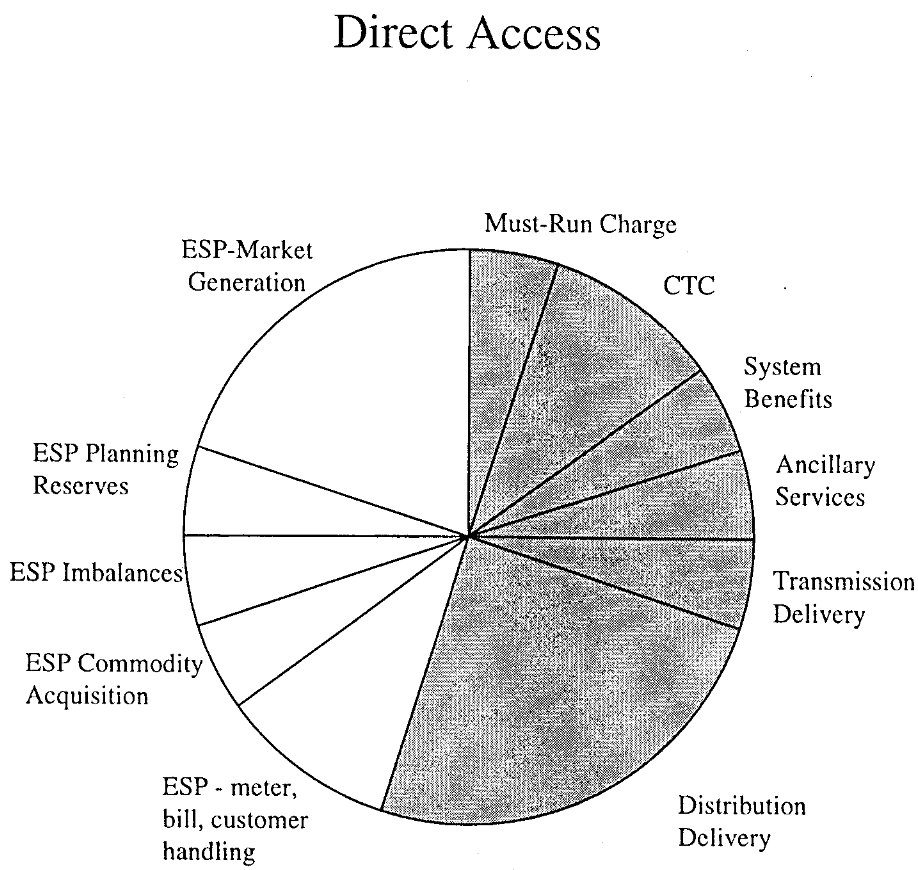
Q. Does this conclude your testimony?

A. Yes.

[1] We note that the PUCN's standard of conduct will be modified by the PUCN to reflect recent legislation that expressly allows the wires companies and their affiliates to share a common name, logo, trademark and service mark.

The Retail Product





Note: Shaded areas represent non-competitive services.
White areas represent competitive services.

CUSTOMER EXAMPLES
COMPARING STANDARD OFFER RATES TO DIRECT ACCESS RATES AND MARKET PRICES

Rate Schedule DA-GS1 Direct Access General Service

	(1) Palo Verde at 100% Load Factor ($/kWh)	(2) Adj. For Load Profile ($/kWh)	(3) Adj. For 8% Losses ($/kWh)	(4) Total Delivered Commodity At Secondary ($/kWh) (1)+(2)+(3)	(5) Distribution ($/kWh)	(6) Transmission ($/kWh)	(7) Ancillary Services ($/kWh)	(8) CTC ($/kWh)	(9) System Benefits ($/kWh)	(10) Must Run Charge ($/kWh)	(11) Direct Access Bundeled Price ($/kWh) (4)+(5)+(6)+(7)+(8)+(9)	(12) Retail Std. Offer (E-32) ($/kWh)	(13) Implied Shopping Credit ($/kWh) (12)-(5)-(6)-(7)-(8)-(9)	(14) Difference ($/kWh) (13)-(4)	(15) Annual Volume Weighting
Jul-99	0.03648	0.00173	0.00332	0.04153	0.02961	0.00348	0.00080	0.00666	0.00115	See Footnote	0.08323	0.07576	0.03406	(0.00747)	8.32%
Aug-99	0.04724	0.00310	0.00438	0.05472	0.02961	0.00348	0.00080	0.00666	0.00115	See Footnote	0.09642	0.07576	0.03406	(0.02066)	8.33%
Sep-99	0.04266	0.00164	0.00385	0.04815	0.02961	0.00348	0.00080	0.00666	0.00115	See Footnote	0.08985	0.07576	0.03406	(0.01409)	8.30%
Oct-99	0.02885	0.00097	0.00259	0.03241	0.02961	0.00348	0.00080	0.00666	0.00115	See Footnote	0.07411	0.07576	0.03406	0.00165	8.36%
Nov-99	0.02649	0.00056	0.00235	0.02940	0.02655	0.00348	0.00080	0.00666	0.00115	See Footnote	0.06804	0.06805	0.02941	0.00001	8.35%
Dec-99	0.02769	0.00052	0.00245	0.03066	0.02655	0.00348	0.00080	0.00666	0.00115	See Footnote	0.06930	0.06805	0.02941	(0.00125)	8.30%
Jan-00	0.02425	0.00093	0.00219	0.02737	0.02543	0.00348	0.00080	0.00603	0.00115	See Footnote	0.06426	0.06805	0.03116	0.00379	8.36%
Feb-00	0.02133	0.00065	0.00191	0.02389	0.02543	0.00348	0.00080	0.00603	0.00115	See Footnote	0.06078	0.06805	0.03116	0.00727	8.38%
Mar-00	0.02025	0.00057	0.00181	0.02263	0.02543	0.00348	0.00080	0.00603	0.00115	See Footnote	0.05952	0.06805	0.03116	0.00853	8.39%
Apr-00	0.02059	0.00061	0.00184	0.02304	0.02543	0.00348	0.00080	0.00603	0.00115	See Footnote	0.05993	0.06805	0.03116	0.00812	8.28%
May-00	0.01952	0.00131	0.00181	0.02264	0.02543	0.00348	0.00080	0.00603	0.00115	See Footnote	0.05953	0.06805	0.03116	0.00852	8.27%
Jun-00	0.02221	0.00160	0.00207	0.02588	0.02836	0.00348	0.00080	0.00603	0.00115	See Footnote	0.06570	0.07576	0.03594	0.01006	8.35%
															100.00%
12-Month Average	0.02813			0.03186									0.03223		0.00038 $/kWh

Rate Schedule DA-GS10 Direct Access General Service

	(1) Palo Verde at 100% Load Factor ($/kWh)	(2) Adj. For Load Profile ($/kWh)	(3) Adj. For 3% Losses ($/kWh)	(4) Total Delivered Commodity At Primary ($/kWh) (1)+(2)+(3)	(5) Distribution ($/kWh)	(6) Transmission ($/kWh)	(7) Ancillary Services ($/kWh)	(8) CTC ($/kWh)	(9) System Benefits ($/kWh)	(10) Must Run Charge ($/kWh)	(11) Direct Access Bundeled Price ($/kWh) (4)+(5)+(6)+(7)+(8)+(9)	(12) Retail Std. Offer (E-34) ($/kWh)	(13) Implied Shopping Credit ($/kWh) (12)-(5)-(6)-(7)-(8)-(9)	(14) Difference ($/kWh) (13)-(4)	(15) Annual Volume Weighting
Jul-99	0.03648	0.00132	0.00117	0.03897	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.06412	0.05394	0.02879	(0.01018)	8.33%
Aug-99	0.04724	0.00189	0.00152	0.05065	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.07580	0.05394	0.02879	(0.02186)	8.33%
Sep-99	0.04266	0.00132	0.00136	0.04534	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.07049	0.05394	0.02879	(0.01655)	8.34%
Oct-99	0.02885	0.00055	0.00091	0.03031	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.05546	0.05394	0.02879	(0.00152)	8.33%
Nov-99	0.02649	0.00045	0.00083	0.02777	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.05292	0.05394	0.02879	0.00102	8.34%
Dec-99	0.02769	0.00041	0.00087	0.02897	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.05412	0.05394	0.02879	(0.00018)	8.33%
Jan-00	0.02425	0.00052	0.00077	0.02554	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04927	0.05394	0.03021	0.00467	8.33%
Feb-00	0.02133	0.00052	0.00068	0.02253	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04626	0.05394	0.03021	0.00768	8.35%
Mar-00	0.02025	0.00045	0.00064	0.02134	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04507	0.05394	0.03021	0.00887	8.33%
Apr-00	0.02059	0.00048	0.00065	0.02172	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04545	0.05394	0.03021	0.00849	8.34%
May-00	0.01952	0.00063	0.00062	0.02077	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04450	0.05394	0.03021	0.00944	8.33%
Jun-00	0.02221	0.00126	0.00073	0.02420	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04793	0.05394	0.03021	0.00601	8.34%
															100.00%
12-Month Average	0.02813			0.02984									0.02950		(0.00034) $/kWh

Inputs	Palo Verde 100 % LF	Office bldg @ 50% LF		Palo Verde 100 % LF	Office bldg @75% LF
	$ 36.48	$ 38.21		$ 36.48	$ 37.80
	$ 47.24	$ 50.34		$ 47.24	$ 49.13
DA-GS1	$ 42.66	$ 44.30	DA-GS10	$ 42.66	$ 43.98
	$ 28.85	$ 29.82		$ 28.85	$ 29.40
500 kW	$ 26.49	$ 27.05	3 MW	$ 26.49	$ 26.94
50% Load Factor	$ 27.69	$ 28.21	75% Load Factor	$ 27.69	$ 28.10
	$ 24.25	$ 25.18		$ 24.25	$ 24.77
	$ 21.33	$ 21.98		$ 21.33	$ 21.85
	$ 20.25	$ 20.82		$ 20.25	$ 20.70
	$ 20.59	$ 21.20		$ 20.59	$ 21.07
	$ 19.52	$ 20.83		$ 19.52	$ 20.15
	$ 22.21	$ 23.81		$ 22.21	$ 23.47

Footnotes:

Enron did not estimate the incremental above market cost of purchasing Must Offer energy during Must Run conditions due to the difficulty of quantifying.
Palo Verde 100% LF prices are based on the NYMEX PV Closing Prices on June 21, 1999, adjusted downward by California PX Off/On Peak Ratios.

COMPARISON OF
MARGINAL STANDARD OFFER RATES TO
MARGINAL DIRECT ACCESS RATES AND MARKET PRICES*

	(1) Standard Offer E-32 Additional kWh Rate $/MWh	(2) Direct Access GS-1 & NYMEX PV On-Peak** $/MWh	(3) Direct Access GS-1 & NYMEX Adjusted Off-Peak** $/MWh	(4) Standard Offer E-34 All kWh Rate $/MWh	(5) Direct Access GS-10 & NYMEX PV On-Peak*** $/MWh	(6) Direct Access GS-10 & NYMEX Adjusted Off-Peak*** $/MWh
Jul-99	47.56	68.44	46.29	32.88	57.31	36.29
Aug-99	47.56	84.48	52.22	32.88	72.52	41.92
Sep-99	47.56	75.29	52.83	32.88	63.80	42.50
Oct-99	47.56	54.59	45.37	32.88	44.17	35.42
Nov-99	42.52	49.36	41.74	32.88	41.07	33.85
Dec-99	42.52	50.44	43.33	32.88	42.10	35.36
Jan-00	42.52	46.77	37.93	32.88	38.71	30.32
Feb-00	42.52	43.51	34.85	32.88	35.62	27.40
Mar-00	42.52	41.88	34.29	32.88	34.07	26.87
Apr-00	42.52	42.43	34.43	32.88	34.58	27.00
May-00	42.52	42.43	31.74	32.88	34.58	24.45
Jun-00	47.56	51.92	30.33	32.88	41.80	21.32
12-Month Average	44.62	54.29	40.45	32.88	45.03	31.89

*NYMEX PV Prices are based on closing prices on June 21, 1999. The Off-Peak Prices are adjusted by historical California PX Off/On Peak Ratios.
** Includes per kWh charge for Distribution at Secondary Voltage Service Level and System Benefits. The NYMEX commodity price is adjusted for line losses of 8%.
*** Includes per kWh charge for Distribution at Primary Voltage Service Level and System Benefits. The NYMEX commodity price is adjusted for line losses of 3%.

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Docket No. 97-5034

In re proposed rulemaking to establish

standards of conduct and related requirements

for distribution companies and affiliates.

At a general session of the Public Utilities Commission of Nevada, held at its offices on December 18, 1998.

PRESENT:

Chairman Judy M. Sheldrew

Commissioner Timothy Hay

Commissioner Lucy A. Stewart

Commission Secretary Jeanne Reynolds

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

1. In March 1998, the Commission first issued a proposed regulation for comment and hearing in Docket No. 97-5034. The proposed regulation consists of standards of conduct and related requirements for distribution companies (electric distribution utilities and natural gas local distribution companies) and their affiliates. The regulation was necessitated by the enactment of NRS 704.965 to 704.999, inclusive. On March 30 and April 2, 1998, the Commission held a workshop, the Commission made substantive changes to the proposed regulation and re-issued it for further comment and hearing. Further revisions to the proposed regulation were made; subsequent hearings were held on June 30 (and continued on July 20, 1998); September 29, 1998; November 6, 1998; and December 4, 1998.

2. The Legislative Counsel Bureau has reviewed this regulation and has returned it in a format suitable for codification in the Nevada Administrative Code.

3. At a duly-noticed agenda meeting on December 18, 1998, the Commission voted to adopt the amendments to Chapter 704 of the NAC, which are attached to this Order, as permanent regulations.

Therefore, based upon the foregoing findings and conclusions, it is hereby ORDERED that:

1. The Commission hereby adopts the amendments to Chapter 704, which are attached to this order and incorporated herein by reference, as permanent regulations in accordance with the provisions of NRS 233B.

2. The attached permanent regulations shall be forwarded to the legislative counsel for incorporation into the Nevada Administrative Code.

3. The Commission retains jurisdiction for the purpose of correcting any errors which may have occurred in the drafting or issuance of this Order.

By the Commission,

JUDY M. SHELDREW, Chairman

TIMOTHY HAY, Commissioner

LUCY A. STEWART, Commissioner

Attest: JEANNE REYNOLDS, Commission Secretary

Dated: 12/30/98 Carson City, Nevada

ADOPTED REGULATION OF THE

PUBLIC UTILITIES COMMISSION OF NEVADA

(Adopted December 18, 1998)

LCB File No. R087-98

December 11, 1998

Explanation - matter in *italics* is new; matter in brackets [ ] is material to be omitted.

AUTHORITY: §§ 2-31, NRS 703.025, 704.980, 704.981 and 704.998.

Section 1. Chapter 704 of the NAC is hereby amended by adding thereto the provisions set forth as sections 2 to 31, inclusive, of this regulation.

Sec. 2. *As used in Section 2 to 31, inclusive, of this regulation, unless the context otherwise requires, the words and terms defined in sections 3 to 7, inclusive, of this regulation have the meanings ascribed to them in those sections.*

Sec. 3. *"Affiliate" means a company that is a branch, division or subsidiary of a distribution company that:*

1. Provides a potentially competitive or discretionary electric or natural gas service; or

2. Is a provider of last resort as described in NRS 704.982.

Sec. 4. *"Customer" means the retail purchaser of electric or natural gas service.*

Sec. 5. *"Distribution company" includes:*

1. An electric distribution utility as defined in NRS 704.970; and

2. A seller of any noncompetitive component of natural gas service.

Sec. 6. *"Noncompetitive service" means any electric or natural gas service determined by statute or by the commission to be unsuitable for purchase by customers from alternative sellers.*

Sec. 7. *"Potentially competitive service" means a component of electric or natural gas service determined by the commission to be suitable for purchase by customers from alternative sellers. The term includes any potentially competitive electric service that is deemed to be effectively competitive pursuant to NRS 704.976.*

Sec. 8. *1. Sections 2 to 31, inclusive, of this regulation:*

(a) Apply to the provision of services as set forth in NRS 704.961 to 704.999, inclusive.

(b) Do not apply to a public utility that supplies natural gas which is not regulated under an alternative plan established pursuant to NRS 704.997.

2. The provisions of sections 2 to 31, inclusive, of this regulation are not in any way restricted by the provisions of NAC 704.270 to 704.2725, inclusive.

Sec. 9. *1. A distribution company may not provide any potentially competitive or discretionary electric natural gas service.*

2. An affiliate of a distribution company may provide a potentially competitive or discretionary electric or natural gas service upon approval by the commission and in accordance with sections 2 to 31, inclusive, of this regulation.

Sec. 10. *A distribution company shall designate an officer to evaluate and certify compliance* with sections 2 to 31, inclusive, of this regulation.

Sec. 11. *1. An affiliate shall:*

(a) Be a separate corporate entity from the distribution company;

(b) Operate independently from the distribution company;

(c) Maintain books, records and accounts in the manner prescribed by the commission;

(d) Keep its books, records and accounts separate from the books, records and accounts kept by the distribution company;

(e) Not have officers, directors or employee in common with the distribution company, except that the chairman of the distribution company or of the holding company of the distribution company may serve on the board of directors of the affiliate;

(f) Not have any member on its board of directors who is also an employee or officer of the distribution company, except as otherwise provided in paragraph (e);

(g) Not obtain credit pursuant to an arrangement that would allow a creditor, upon default, to have recourse to the assets of the distribution company; and

(h) Not use office space, office equipment or office services provided by the distribution company, unless the affiliate executes with the distribution company a contract that is approved by the commission. The affiliate and the distribution company must:

(1) File the contract with the commission as a joint application not later than 6 months before the effective date of the contract; and

(2) Demonstrate to the commission that the contract:

(I) Does not circumvent the provisions of sections 2 to 31, inclusive, of this regulation;

(II) Preserves an arm's length business relationship between an affiliate and the distribution company;

(III) Does not interfere with the development of effective competition;

(IV) Will result in minimal risk of anticompetitive behavior by the affiliate or distribution company and;

(V) Will result in minimal regulatory expenses to prevent anticompetitive behavior.

The contract must not become effective until the commission approves the contract. Unless the commission determines otherwise, all office space, office equipment and office services provided by the distribution company pursuant to the contract are subject to the provisions of section 12 of this regulation.

2. A distribution company shall document and report quarterly to the commission each occasion that:

(a) An employee of the distribution company becomes an employee of an affiliate; or

(b) An employee of an affiliate becomes an employee of the distribution company.

3. An employee of a distribution company who is hired by an affiliate:

(a) Shall not remove proprietary property or information from the distribution company;

(b) Shall not provide the affiliate with proprietary property or information of the distribution company;

(c) Shall not use proprietary property or information of the distribution company on behalf of the affiliate; and

(d) Shall, before he becomes an employee of the affiliate, sign a statement indicating that the employee has read and will abide by the restrictions set forth in this section and understands that a violation of a provision of this section could subject him to the penalties set forth in section 30 of this regulation.

Sec. 12. *When dealing with an affiliate, a distribution company:*

1. Shall not discriminate between the affiliate and another entity that competes with the affiliate in the provision or procurement of goods, services, facilities and information, or in the establishment of standards.

2. Shall not refuse to provide an entity that is in competition with an affiliate with goods, services, facilities or information which the commission determines the distribution company is reasonably capable of providing to its affiliate, regardless of whether the distribution company currently offers such goods, services, facilities or information to an affiliate.

3. Shall not, when providing or procuring, or declining to provide or procure, goods, services, facilities or information, or when establishing standards, provide, attempt to provide or conspire with another person, including, without limitation, an affiliate, to provide:

(a) A competitive advantage to an affiliate; or

(b) A competitive disadvantage to a competitor of an affiliate.

4. Shall account for all transaction with each affiliate in accordance with accounting principles designated or approved by the commission.

5. Shall, if it offers to an affiliate a good or service other than a good or service provided by a contract pursuant to paragraph (h) of subsection 1 of section 11 of this regulation, offer the same service to all similarly situated nonaffiliated entities.

6. Shall, at the same time it offers to an affiliate a good or service other than a good or service provided by contract pursuant to paragraph (h) of subsection 1 of section 11 of this regulation, offer the same service to nonaffiliated entities by using the mechanism described in subsection 7.

7. Shall provide a mechanism that is accessible to the public, such as an electronic bulletin board, for all interested entities to receive promptly pertinent information concerning:

(a) Services which the distribution company provides;

(b) Any discounted services which the distribution company offers to an affiliate; and

(c) Any transaction between the distribution company and an affiliate.

8. Shall not represent that it will provide an affiliate or a customer of an affiliate with different treatment regarding the provision of services as a result of affiliation with the distribution company than the treatment the distribution company provides a nonaffiliated provider of service and its customers.

9. Shall not provide an affiliate or a customer of an affiliate with preferences over a nonaffiliated supplier or its customers, including, without limitation, preferences in terms and conditions of service or pricing, or in timing of service.

10. Shall apply a tariff provision that allows for discretion in its application in the same manner for an affiliate and customers of the affiliate as it does for another market participant and its customers.

11. Shall strictly enforce mandatory tariff provisions.

12. Shall not condition or otherwise tie the provision of a utility service or the availability of discounts, rates, other charges, fees, rebates or waivers of terms and conditions to the taking of any goods or services from an affiliate.

12. Shall not:

(a) Refer a potential customer to an affiliate;

(b) Provide information to an affiliate regarding a potential business arrangement between a potential customer and the affiliate;

(c) Except as otherwise prescribed by the commission, acquire information on behalf of or to provide to an affiliate;

(d) Share with an affiliate a market analysis report, survey, research or any other type of report that is proprietary or not available to the public, including, without limitation, a forecast, planning or strategic report;

(e) Give an appearance that the distribution company speaks on behalf of an affiliate or that a customer will receive preferential treatment as a consequence of conducting business with an affiliate; or

(f) Give an appearance to a third party that an affiliate speaks on behalf of the distribution company.

Nothing in this subsection prohibits an affiliate from billing for distribution services in a manner consistent with sections 2 to 31, inclusive, of this regulation.

14. Shall make any discount or waiver of all or of part of a charge or fee available to all market participants.

15. Shall not share the office space, equipment or services of an affiliate or access the computer information systems of an affiliate, unless the affiliate executes a contract with the distribution company that has been approved by the commission pursuant to the procedures set forth in paragraph (h) of subsection 1 of section 11 of this regulation.

Sec. 13. *A distribution company shall provide information about specific customers to its affiliates and to nonaffiliated entities:*

1. On a strictly nondiscriminatory basis;

2. Only with the consent of a customer; and

3. In accordance with the rules or standards required by the commission.

Sec. 14. *Information that is not specific to a customer, including, without limitation, information concerning the goods, services, purchases, sales or operations of the distribution company, may be made available to an affiliate only if the distribution company:*

1. Makes such information contemporaneously available to all alternative sellers at the same price, terms and conditions; and

2. Keeps the information open to public inspection.

Sec. 15. *Except as otherwise authorized by the commission, a distribution company shall not provide a person with a list of alternative sellers.*

Sec. 16. *Except as otherwise provided in sections 2 to 31, inclusive, of this regulation, a distribution company shall not offer or provide a customer with advice or assistance of any kind regarding an affiliate or another service provider.*

Sec. 17. *A distribution company shall:*

1. Keep for at least 3 years a record documenting a transaction with an affiliate, including, without limitation, a record documenting:

(a) A waiver of a tariff;

(b) A waiver of a contract provision;

(c) A discount given by the distribution company to the affiliate;

(d) Contracts or related bids for the provision of work, products or services for or from an affiliate.

2. Make the records that the distribution company is required to maintain pursuant to subsection 1 available for review by third parties upon notice of at least 72 hours, unless the distribution company makes a different agreement with a third party concerning the review of the record.

Sec. 18. *1. If a distribution company provides an affiliate with a discount, rebate or other waiver of a charge or fee, the distribution company shall, at the time the service for which the distribution company is giving the discount, rebate or other waiver of a charge or fee is first provided, post on the electronic bulletin board of the distribution company a notice which included, without limitation:*

(a) The name of the affiliate involved in the transaction;

(b) The actual rate charged by the distribution company;

(c) The maximum rate that the distribution company may charge pursuant to its tariff;

(d) The period during which the discount or waiver applies;

(e) The quantities involved in the transaction;

(f) The delivery points involved in the transaction;

(g) Any conditions or requirements applicable to the discount or waiver; and

(h) The procedures through which a nonaffiliated entity may request and receive a comparable discount, rebate or other waiver of a charge or fee.

2. This section does not provide a distribution company with any authority not otherwise existing to grant a discount, rebate or other waiver of a charger or fee.

Sec. 19. *1. A distribution company that provides an affiliate with a discounted rate, rebate or other waiver of a charge or fee for a service shall, for each billing period, maintain in its records:*

(a) The name of the affiliate to which the distribution company is providing services pursuant to the transaction;

(b) A description of the role of the affiliate in the transaction, including, without limitation, whether the affiliate will act as a transporter, marketer, supplier or seller;

(c) The duration of the discount or waiver;

(d) The maximum rate that the distribution company may charge pursuant to its tariff;

(e) The rate or fee that the distribution company charges during the billing period; and

(f) The quantity of products or services scheduled at the discounted rate during the billing period for each delivery point.

2. All records maintained pursuant to this section must also conform to rules of the Federal Energy Regulatory Commission, where applicable.

3. This section does not provide the distribution company with any authority not otherwise existing to grant such discount, rebate or other waiver of a charge or fee.

Sec. 20. *1. Unless the commission specifies otherwise, a distribution company with an affiliate shall obtain and pay for an audit 6 months after the affiliate first provides service to customers and once every year thereafter.*

2. The audit required pursuant to subsection 1 must be conducted by an independent auditor selected by the commission.

3. The auditor shall determine whether a distribution company has complied with all pertinent regulations, including, without limitation, whether the distribution company has:

(a) Complied with the separate accounting requirements set forth in section 11 of this regulation; and

(b) Provided information or services to affiliated and nonaffiliated entities on a nondiscriminatory basis.

4. The auditor shall submit the results of the audit to the commission.

5. The commission will make the results of the audit available for public inspection.

6. Any person may submit comments on the final audit report.

Sec. 21. *For purposes of conducting an audit pursuant to section 20 of this regulation, the distribution company and its affiliate shall provide the independent auditor, the commission staff, the bureau of consumer protection in the office of the attorney general and the commission access to:*

1. Financial accounts and records which:

(a) Verify that the transactions conducted between the distribution company and its affiliates are authorized by and conducted in accordance with the provisions of NRS 704.961 to 704.999, inclusive, and sections 2 to 31, inclusive, of this regulation; and

(b) Relate to the regulation of rates;

2. All records in any form relating to the provision of information or services to affiliated or nonaffiliated entities; and

3. The working papers and supporting materials of any auditor who performed an audit pursuant to section 20 of this regulation.

Sec. 22. *Except as otherwise stated in its approved tariff, a distribution company:*

1. Shall fulfill a request from a nonaffiliated entity for service within a period no longer than the period in which it fulfills such a request for itself or for an affiliate;

2. Shall charge each affiliate an amount for service that is no less than the amount charged to any nonaffiliated entity for the same service;

3. May, in accordance with the provisions of paragraph (h) of subsection 1 of section 11 of this regulation, provide an affiliate with facilities, services and information if the distribution company makes such facilities, services and information available to all nonaffiliated entities at the same rates and on the same terms and conditions and the costs are allocated in a manner acceptable to the commission;

4. May not market or sell services that are provided by an affiliate; and

5. May not state that it is an affiliate of a potentially competitive or discretionary service unless the statement complies with the requirements set forth in subsection 6 of section 24 of this regulation.

Sec. 23. *1. If a distribution company transfers goods or services to an affiliate, the distribution company must price the goods or services at fair market value or fully loaded cost, whichever is higher.*

2. If an affiliate transfers goods or services to the distribution company, the affiliate shall price the goods or services at fair market value or fully loaded cost, whichever is less.

3. As used in this section, "fully loaded cost" means the direct costs of goods and services plus all applicable indirect charges and overhead costs, including, without limitation, a reasonable rate of return.

Sec. 24. *An affiliate:*

1. Shall not market or otherwise sell services jointly with the distribution company;

2. Shall not have a name, logo, trademark, service mark or trade name that is deceptively similar to that of the distribution company, except that an affiliate which has been designated by the commission as a provider of last resort service pursuant to NRS 704.982 may have a name, logo, trademark, service mark or trade name that is similar or identical to that of the distribution company if the affiliate has been specifically authorized to do so by the commission, subject to any conditions that commission deems necessary;

3. Shall not have the logo, trademark or other corporate identification of the distribution company appear on documents of the affiliate or on goods or merchandise sold by the affiliate, unless the commission:

(a) Designates the affiliate to be the provider of last resort service pursuant to NRS 704.982; and

(b) Specifically authorizes, subject to any conditions that the commission deems necessary, the affiliate to use the name, logo, trademark, service mark or trade name;

4. Shall not use the name of the distribution company in any material that the affiliate circulates, unless the affiliate provides with the material the information described in subsection 6;

5. Shall not us space in the correspondence of the distribution company or any other form of information about the distribution company for the purpose of advertising the services of the affiliate; and

6. Shall not advertise its affiliation with the distribution company, unless the affiliate includes each of the following statements in a manner no less prominent that the statement of affiliation:

(a) (Name of the affiliate) is not the same corporation as (name of distribution company). (Name of affiliate) has separate management and separate employees.

(b) (Name of affiliate)'s affiliation with (name of distribution company) does not entitle (name of affiliate) to any special endorsement of the public utilities commission of Nevada.

(c) The safety, reliability and cost of distribution service received by customers of (name of affiliate) will be equivalent to that received by customers of nonaffiliated companies.

Sec. 25. *An affiliate of a distribution company shall not offer goods or services until the affiliate satisfies any applicable requirements set forth in section 2 to 31, inclusive, of this regulation, except the appointment of an auditor pursuant to section 20 of this regulation.*

Sec. 26. *Each transaction that violates the provisions of sections 2 to 31, inclusive, of this regulation, will be considered a separate violation.*

Sec. 27. *1. A person or business may complain to the commission or distribution company in writing, setting forth any act or thing allegedly done or not done by a distribution company or affiliate in violation* *of sections 2 to 31, inclusive, of this regulation.*

2. Upon request of a complainant who is a current or former employee of a distribution company or an affiliate, the commission will maintain the confidentiality of the complainant until the end of any resulting investigation or longer if the commission deems it necessary.

3. The distribution company shall refer all complaints, whether written or oral, to a designated representative of the distribution company, who shall:

(a) Acknowledge receipt of the complaint in writing to the complainant within 5 working days after receiving the complaint;

(b) Prepare a written summary of the complaint which must include, without limitation:

(1) The name of the complainant; and

(2) A detailed factual report of the complaint, including, without limitation:

(I) The relevant dates;

(II) The names of the companies involved;

(III) The names of the employees involved; and

(IV) The details of the claim;

(c) Conduct a preliminary investigation; and

(d) Communication the results of the preliminary investigation, including, without limitation, a description of any course of action that was taken as a result of the investigation, in writing to the complainant not more than 20 business days after the designated representative received the complaint.

4. The distribution company shall:

(a) Maintain a public log of all new, pending and resolved complaints; and

(b) Make the public log available to the commission and the bureau of consumer protection in the office of the attorney general not more than 10 business days after the end of each month, which must include, without limitation:

(1) A written summary of each complaint; and

(2) A written summary of the manner in which each complaint was resolved or, if applicable, an explanation of the reason why a complaint is still pending.

Sec. 28. *1. The division of consumer complaint resolution shall investigate any complaint concerning a violation of the provisions of NRS 703.290 and sections 2 to 31, inclusive, of this regulation.*

2. If the division transmits a complaint to the commission and the commission determines that probable cause exists for the complaint, the commission will:

(a) Order that a hearing be held;

(b) Provide notice of the hearing to the parties; and

(c) Conduct the hearing as it would any other hearing.

Sec. 29. *After a hearing has been held pursuant to section 28 of this regulation, the commission, when enforcing the provisions of sections 2 to 31, inclusive, of this regulation or an order of the commission that relates to sections 2 to 31, inclusive, of this regulation, may, without limitation:*

1. Terminate a transaction if the violation caused material harm to the competitive market;

2. Prospectively limit or restrict the amount, percentage or value of transactions entered into between a distribution company and its affiliates;

3. Assess a penalty pursuant to the provisions of section 30 of this regulation; or

4. Apply any other remedy which is available to the commission.

Sec. 30. *1. A penalty assessed by the commission must reflect the actual or potential injury, or both, to ratepayers and competitors, and the gravity of the violation.*

2. Repeated violations will require more sever penalties.

3. In addition to any other penalties, the commission may subject a distribution company to a penalty of not more than $20,000 for each time the distribution company:

(a) Violates a provision of sections 2 to 31, inclusive, of this regulation;

(b) Fails to perform a contractual duty; or

(c) Fails, neglects or refuses to obey an order, regulation, directive or requirement of the commission.

4. Penalties for a supplier of a noncompetitive natural gas distribution service are limited pursuant to the provisions of NRS 703.380.

5. The commission may deem a violation that continues for more than 1 day to be a separate violation for each day the violation continues.

6. A penalty or other remedy imposed by the commission will in no manner preclude the right of a party to pursue a private action in a court of competent jurisdiction.

7. A fine or penalty collected pursuant to the provisions of section 2 to 31, inclusive, of this regulation, must be deposited in the state treasury pursuant to NRS 703.147 for the purposes identified therein.

8. For each violation of the provisions of sections 2 to 31, inclusive, of this regulation, the affiliate shall include in one monthly billing packet a notice, written by the commission, that informs the public of the substance of the violation and explains how members of the public can report similar violations in the future.

9. The penalties set forth in this section do not preclude any other penalty from being imposed pursuant to sections 2 to 31, inclusive, of this regulation or any other provision of law.

Sec. 31. *1. If the commission finds in two separate orders that a distribution company has materially violated the provisions of sections 2 to 31, inclusive, of this regulation more than twice in a period of 12 months, the distribution company may not, for 1 year after the date of the findings by the commission, enter into a transaction with an affiliate that was involved in the violations.*

2. If a distribution company violates the provisions of subsection 1 by entering into a prohibited transaction with an affiliate, the commission may:

(a) Extend the period in which the distribution company is prohibited from entering into a transaction with the affiliate; or

(b) Permanently prohibit the distribution company from entering into a transaction with the affiliate.

3. The penalties set forth in this section do not preclude any other penalty from being imposed pursuant to sections 2 to 31, inclusive, of this regulation or any other provision of law.

Exhibit HJK 2 - Revised

CUSTOMER EXAMPLES
COMPARING STANDARD OFFER RATES TO
DIRECT ACCESS RATES AND MARKET PRICES

Rate Schedule DA-GS1 Direct Access General Service

	(1) Palo Verde at 100% Load Factor ($/kWh)	(2) Adj. For Load Profile ($/kWh)	(3) Adj. For 8% Losses ($/kWh)	(4) Total Delivered Commodity At Secondary ($/kWh) (1)+(2)+(3)	(5) Distribution ($/kWh)	(6) Transmission ($/kWh)	(7) Ancillary Services ($/kWh)	(8) CTC ($/kWh)	(9) System Benefits ($/kWh)	(10) Must Run Charge ($/kWh)	(11) Direct Access Bundeled Price ($/kWh) (4)+(5)+(6)+(7)+(8)+(9)	(12) Retail Std. Offer (E-32) ($/kWh)	(13) Implied Shopping Credit ($/kWh) (12)-(5)-(6)-(7)-(8)-(9)	(14) Difference ($/kWh) (13)-(4)	(15) Annual Volume Weighting
Jul-99	0.03648	0.00173	0.00332	0.04153	0.02961	0.00348	0.00080	0.00666	0.00115	See Footnote	0.08323	0.07576	0.03406	(0.00747)	8.32%
Aug-99	0.04724	0.00310	0.00438	0.05472	0.02961	0.00348	0.00080	0.00666	0.00115	See Footnote	0.09642	0.07576	0.03406	(0.02066)	8.33%
Sep-99	0.04266	0.00164	0.00385	0.04815	0.02961	0.00348	0.00080	0.00666	0.00115	See Footnote	0.08985	0.07576	0.03406	(0.01409)	8.30%
Oct-99	0.02885	0.00097	0.00259	0.03241	0.02961	0.00348	0.00080	0.00666	0.00115	See Footnote	0.07411	0.07576	0.03406	0.00165	8.36%
Nov-99	0.02649	0.00056	0.00235	0.02940	0.02655	0.00348	0.00080	0.00666	0.00115	See Footnote	0.06804	0.06805	0.02941	0.00001	8.35%
Dec-99	0.02769	0.00052	0.00245	0.03066	0.02655	0.00348	0.00080	0.00666	0.00115	See Footnote	0.06930	0.06805	0.02941	(0.00125)	8.30%
Jan-00	0.02425	0.00093	0.00219	0.02737	0.02543	0.00348	0.00080	0.00603	0.00115	See Footnote	0.06426	0.06805	0.03116	0.00379	8.36%
Feb-00	0.02133	0.00065	0.00191	0.02389	0.02543	0.00348	0.00080	0.00603	0.00115	See Footnote	0.06078	0.06805	0.03116	0.00727	8.38%
Mar-00	0.02025	0.00057	0.00181	0.02263	0.02543	0.00348	0.00080	0.00603	0.00115	See Footnote	0.05952	0.06805	0.03116	0.00853	8.39%
Apr-00	0.02059	0.00061	0.00184	0.02304	0.02543	0.00348	0.00080	0.00603	0.00115	See Footnote	0.05993	0.06805	0.03116	0.00812	8.28%
May-00	0.01952	0.00131	0.00181	0.02264	0.02543	0.00348	0.00080	0.00603	0.00115	See Footnote	0.05953	0.06805	0.03116	0.00852	8.27%
Jun-00	0.02221	0.00160	0.00207	0.02588	0.02836	0.00348	0.00080	0.00603	0.00115	See Footnote	0.06570	0.07576	0.03594	0.01006	8.35%
															100.00%
12-Month Average	0.02813			0.03186									0.03223		0.00038 $/kWh

Rate Schedule DA-GS10 Direct Access General Service

	(1) Palo Verde at 100% Load Factor ($/kWh)	(2) Adj. For Load Profile ($/kWh)	(3) Adj. For 3% Losses ($/kWh)	(4) Total Delivered Commodity At Primary ($/kWh) (1)+(2)+(3)	(5) Distribution ($/kWh)	(6) Transmission ($/kWh)	(7) Ancillary Services ($/kWh)	(8) CTC ($/kWh)	(9) System Benefits ($/kWh)	(10) Must Run Charge ($/kWh)	(11) Direct Access Bundeled Price ($/kWh) (4)+(5)+(6)+(7)+(8)+(9)	(12) Retail Std. Offer (E-34) ($/kWh)	(13) Implied Shopping Credit ($/kWh) (12)-(5)-(6)-(7)-(8)-(9)	(14) Difference ($/kWh) (13)-(4)	(15) Annual Volume Weighting
Jul-99	0.03648	0.00132	0.00117	0.03897	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.06412	0.05394	0.02879	(0.01018)	8.33%
Aug-99	0.04724	0.00189	0.00152	0.05065	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.07580	0.05394	0.02879	(0.02186)	8.33%
Sep-99	0.04266	0.00132	0.00136	0.04534	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.07049	0.05394	0.02879	(0.01655)	8.34%
Oct-99	0.02885	0.00055	0.00091	0.03031	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.05546	0.05394	0.02879	(0.00152)	8.33%
Nov-99	0.02649	0.00045	0.00083	0.02777	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.05292	0.05394	0.02879	0.00102	8.34%
Dec-99	0.02769	0.00041	0.00087	0.02897	0.01565	0.00260	0.00060	0.00515	0.00115	See Footnote	0.05412	0.05394	0.02879	(0.00018)	8.33%
Jan-00	0.02425	0.00052	0.00077	0.02554	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04927	0.05394	0.03021	0.00467	8.33%
Feb-00	0.02133	0.00052	0.00068	0.02253	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04626	0.05394	0.03021	0.00768	8.35%
Mar-00	0.02025	0.00045	0.00064	0.02134	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04507	0.05394	0.03021	0.00887	8.33%
Apr-00	0.02059	0.00048	0.00065	0.02172	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04545	0.05394	0.03021	0.00849	8.34%
May-00	0.01952	0.00063	0.00062	0.02077	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04450	0.05394	0.03021	0.00944	8.33%
Jun-00	0.02221	0.00126	0.00073	0.02420	0.01472	0.00260	0.00060	0.00466	0.00115	See Footnote	0.04793	0.05394	0.03021	0.00601	8.34%
															100.00%
12-Month Average	0.02813			0.02984									0.02950		(0.00034) $/kWh

Inputs	Palo Verde 100 % LF	Office bldg @ 50% LF		Palo Verde 100 % LF	Office bldg @75% LF
	$ 36.48	$ 38.21		$ 36.48	$ 37.80
	$ 47.24	$ 50.34		$ 47.24	$ 49.13
DA-GS1	$ 42.66	$ 44.30	DA-GS10	$ 42.66	$ 43.98
	$ 28.85	$ 29.82		$ 28.85	$ 29.40
500 kW	$ 26.49	$ 27.05	3 MW	$ 26.49	$ 26.94
50% Load Factor	$ 27.69	$ 28.21	75% Load Factor	$ 27.69	$ 28.10
	$ 24.25	$ 25.18		$ 24.25	$ 24.77
	$ 21.33	$ 21.98		$ 21.33	$ 21.85
	$ 20.25	$ 20.82		$ 20.25	$ 20.70
	$ 20.59	$ 21.20		$ 20.59	$ 21.07
	$ 19.52	$ 20.83		$ 19.52	$ 20.15
	$ 22.21	$ 23.81		$ 22.21	$ 23.47

Footnotes:

Enron did not estimate the incremental above market cost of purchasing Must Offer energy during Must Run conditions due to the difficulty of quantifying.
Palo Verde 100% LF prices are based on the NYMEX PV Closing Prices on June 21, 1999, adjusted downward by California PX Off/On Peak Ratios.

APSTABLEibbAVERAGE

EXHIBIT
Admitted
Enron-7

DEFINING "SHOPPING CREDIT"
USING ILLUSTRATIVE NUMBERS

Case 1
Cost-based delivery charges are known

"Top-down approach"

	(cents/kWh)
Bundled Rate	8.0
Less	
Distribution delivery	1.5
Transmission delivery (incl. Ancillary)	0.5
Metering & Billing performed by utility	0.5
Competitive Transition Charge	1.0
System Benefits	0.5
Equals	
Generation Shopping Credit	4.0

Case 2
Cost-based delivery charges are not known

"Bottom-up approach"

	(cents/kWh)
Wholesale Market Price	3.0
Plus	
Adjustment for retail load profile	0.3
Losses	0.2
Portfolio management	0.1
Retail activities (customer acquisition, handling, special metering)	0.4
Equals	
Generation Shopping Credit	4.0

EXHIBIT
Admitted
Enron-8

ILLUSTRATIVE EXAMPLE OF UNBUNDLED PRICES
FOR STANDARD OFFER AND DIRECT ACCESS,
USING "PARALLEL PRICING"

Cost Category	Rate	Standard Offer Prices Bundled	Standard Offer Prices Unbundled	Direct Access Prices Bundled	Direct Access Prices Unbundled
	Basic Service Charge ($)	100		100	
Generation			0		
CTC			0		
Transmission			0		
Distribution			25		25
Customer Services			75		75 (if purchased)
System Benefits			0		
	Demand Charge ($/kW)	5		3	
Generation			2		
CTC			1		1
Transmission			0.5		0.5
Distribution			1.5		1.5
Customer Services			0		
System Benefits			0		
	Energy Charge (cents/kWh)	6		3.5	
Generation			3		
CTC			0		
Transmission			0.5		0.5
Distribution			1		1
Customer Services			0.5		0.5
System Benefits			0.5		0.5

EXHIBIT
Admitted
Enron-9

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
Admitted
S-1

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 ET SEQ.	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. RE-00000C-94-0165

DIRECT

TESTIMONY

OF

RAY T WILLIAMSON

ACTING DIRECTOR

UTILITIES DIVISION

JUNE 30, 1999

I. INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Ray T. Williamson. My business address is the Arizona Corporation Commission (Commission or ACC), 1200 West Washington, Phoenix, Arizona 85007.

Q. What is your position at the Commission?

A. I am Acting Director of the Utilities Division.

Q. Prior to becoming Acting Director, where were you employed?

A. I have been employed at the Commission since 1992 in various positions, including Economist, Senior Rate Analyst and Chief of Economics and Research.

Q. Please describe the balance of your background and experience?

A. My statement of Professional Qualifications is appended to this testimony as Schedule RTW-2.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's concerns and recommendations related to Commission review and approval of the proposed Arizona Public Service Company Settlement Agreement ("Settlement").

II. APPROVAL OF THE SETTLEMENT

Q. Does Staff recommend approval of the Settlement?

A. Yes. Staff recommends approval of the Settlement with certain limited modifications that Staff believes clarify the Settlement's provisions and enhance the opportunity for competition in the transition to a competitive market.

. . .

. . .

Q. Why is Staff recommending approval of the Settlement?

A. Staff believes the proposed Settlement provides certainty and a known path to competition. Staff reviewed the Settlement within the public interest framework of balancing the Settlement's implications for competition in Arizona with the guaranteed rate reductions reflected in the Settlement. This balancing of interest included an evaluation of the immediate benefits of the Settlements' known rate reduction schedules with the Settlement's impact on establishing a truly competitive market that would provide greater future reductions due to competitive pricing pressures.

Q. Why would Staff support addressing the issues through a settlement rather than through evidentiary hearings on the individual issues?

A. Staff wants to foster the development of robust and meaningful competition at the earliest possible date. As a practical matter, if these issues are not addressed in a settlement, it is almost certain that competition would be slower to develop.

Without the resolution of the major issues included in a settlement, it is doubtful whether many competitors would offer service or whether many customers would risk signing a contract for competitive service. Issues such as stranded costs, competition transition charges, market generation credits, final unbundled tariffs and other issues are all matters necessary for competitors and customers to determine whether they will be able to forge a better deal than is available from Affected Utilities.

III. STAFF'S CLARIFICATIONS AND MODIFICATIONS

Q. What clarifications and modifications is Staff proposing to the Settlement?

A. In general terms, Staff's recommendations provide for greater unbundling of tariffs, increase the market generation credit, and clarify provisions concerning certain adjustor mechanisms referred to in the Settlement. These clarifications and modifications to the Settlement are the subject of Staff Witness Lee Smith's testimony.

Q. What are the implications of the direction that the Settlement has suggested for Arizona's competitive retail electric market?

A. The Settlement's implications are important to the eventual success of Arizona's Retail Electric Competition effort. When the Arizona effort to evaluate Retail Electric Competition commenced in 1994, the underlying principle was that competition among a wide range of competitors would drive down the price of electricity and electricity services in Arizona. This belief in the price-reducing forces of competitive action continues today.

However, the Settlement takes an approach that offers the parties that negotiated the settlement and others a specified schedule of rate reductions over time, while discouraging entry of competitors through the adoption of an implicit Market Generation Credit that will not attract competitors to Arizona. As proposed, the Settlement appears to favor guaranteed rate reductions over the establishment of a competitive market during the transition to competition. Staff believes the Commission should do more than approve a Settlement that guarantees a certain level of rate reductions, and in addition, establish a robust competitive market that may well surpass the rate reductions in the settlement as well as encourage the innovation and cost-reducing behavior of dozens or, possibly, hundreds of competitors. This Settlement will accomplish both of these goals if Staff's modifications to the Settlement as outlined in Ms. Smith's testimony are adopted by the Commission.

Q. Why do you believe that the Settlement requires Staff's modifications to encourage a truly competitive market?

Evidence from other States has shown that the manner in which state Public Utility Commission's structure the competitive market has a major impact on how both customers and competitors will react in those markets. For instance, in January 1998, California chose to require a 10% rate reduction for all customers. This took the incentive out of the customer choice. With no risk, most customers merely decided to stay with their utility and receive the automatic 10% reduction. In both California and Massachusetts, the Market Generation Credits were too low to encourage competitors, so few competitors are active in those States and a relatively small number of customers have switched suppliers. According to Staff Witness Lee Smith's testimony, the implicit Market Generation Credit is too low for some customers to be able to make a competitive choice. In addition, Ms. Smith has also concluded that there will be little if any competition for APS metering and billing services due to the Agreement adopting a significantly lower avoided cost credit rather than embedded cost for these services.

IV. IMPACT ON APS' CUSTOMERS

Q. *Is this Settlement a good deal for the customers of APS?*

A. It appears so. The purpose of moving toward retail electric competition is to allow customer choice and lower rates in a changing market structure. The Settlement Agreement allows all customers, whether eligible for competition or not, to get lower rates starting in 1999. This is particularly important for those customers who are unable to switch suppliers and for those whom the competitors may not be interested in serving. Let's take low-income residential customers, for instance. In the filings that the Commission Staff has seen so far, few competitors are planning on targeting residential customers. Even if those customers are eligible to exercise choice, there may not be many competitors willing to offer them service. In a free market, the competitors can choose to sell to any customers that they wish, or choose <u>not</u> to sell to certain customers. It is entirely possible that competitors may decide to by-pass low-income customers completely. If that is the case, this Settlement will ensure that low-income customers of APS will see rate reductions in the coming years, whether they choose another supplier or not.

. . .

. . .

Q. Do you have any reservations about this "good deal"?

A. As I have indicated in my previous comments, the series of rate reductions in the settlement may be less than that which might have resulted from a more competitive environment resulting from a higher implicit Market Generation Credit. Ms. Smith also discusses this point in her testimony.

Q. Is this a better deal than could be obtained without the Settlement?

A. It is uncertain whether a better deal could be obtained without the Settlement. One of the benefits of the Settlement is that it brings immediate and quantifiable benefits to ratepayers, rather than requiring ratepayers to wait an indefinite length of time for benefits that may or may not be greater than those contained in the Settlement. In addition, the Settlement provides certainty, resolves issues, and establishes a path for competition in APS' service territory. The Settlement allows us to put many contentious issues behind us and focus on bringing competition to APS' customers.

V. COMMISSION APPROVALS AND REQUESTED WAIVERS

Q. Are there any Commission approvals inherent in the body of the Proposed Settlement Agreement with which the Staff has concerns?

A. Yes. In Article IV, Section 4.3, the Proposed Settlement contains language pursuant to Arizona Revised Statutes ("A.R.S.") § 40-202(L) that effectively exempts the provision of competitive services by APS and any of its affiliates from regulation as public service corporations. Also in Article IV, Section 4.5, approval by the Commission of the Proposed Settlement constitutes waivers to APS and its affiliates (including its parent) of the Commission's existing affiliated interest rules (A.A.C. R14-2-801, *et.seq.*).

Q. Please state A.R.S. § 40-202(L) for clarification.

A. A.R.S. § 40-202(L) states "[t]he commission by rule or order may exempt or partially exempt any competitive service of any public service corporation from the application of

§ 40-203, § 40-204, subsections A and B and §§ 40-248, 40-250,40-251, 40-285, 40-301, 40-302, 40-303, 40-321, 40-322, 40-331, 40-332, 40-334, 40-365, 40-366, 40-367, 40-374, and 40-401."

Q. Does the Proposed Settlement include all of the above A.R.S. sections?

A. No. A.R.S. § 40-374 is not included in the Proposed Settlement but Staff is not aware of the reason for the exclusion.

Q. Is it Staff's recommendation that the exemptions contained in the Proposed Settlement are inappropriate and should be explicitly denied?

A. No. Staff is recommending that the Commission reserve its approval of the exemptions until such time as the applicability of the statutes to competitive services can be evaluated on an industry-wide basis versus a blanket exemption for APS and its affiliates exclusively.

Q. What is the basis for Staff's recommendation to reserve approval of the exemptions?

A. If the Commission chooses to allow these exemptions, it should be after a complete analysis of the impact of its decision on the development of a competitive market and all affected participants. In addition, this exemption for APS and its affiliates should not provide the vehicle for similar blanket exemptions by other competitive service providers without the benefit of prior analysis of the issues by the Staff and the Commission.

Q. What is Staff's recommendation regarding the requested waivers from the existing affiliate interest rules?

A. Staff is recommending that the Commission adopt the language from the Settlement Agreement that Staff reached with APS in November 1998 as it relates to the requested waivers from the existing affiliated interest rules. The waivers from the existing affiliate interest rules were evaluated in depth by Staff in relation to the November Settlement

. . .

agreement which was subsequently withdrawn. The evaluation resulted in the granting or limiting of some of the requested waivers and are summarized in Exhibit RTW-1. Staff would point out the importance of specifically limiting the request to waive A.A.C. R14-2-804 (A) that requires any affiliate that transacts business with the Utility Distribution Company to open its books and records to Commission review. This request should be viewed in tandem with the Settlement's language regarding Exempt Wholesale Generator status, specifically the "specific determination" appearing at the top of page 7 of the proposed Settlement which states "[t]he Commission has sufficient regulatory authority, resources and <u>access to the books and records of APS and any relevant associate, affiliate, or subsidiary company</u> to exercise its duties under Section 32(k) of PUHCA." (emphasis added).

VI. CONCLUSION

Q. In light of the above, what is Staff's final recommendation?

A. The Commission should approve the Settlement as clarified and modified by Staff.

Q. How would you propose that the Settlement Agreement be modified to address the problems you have outlined above?

A. The Agreement needs to be modified to provide a better balance between the goal of guaranteed rate reductions and the goal of a truly competitive market for retail electric services. This balance can be achieved in a number of different ways. The key to achieving a better balance is to raise the Market Generation Credit and the metering and billing credits to a level where all customer classes will have the opportunity to make a competitive choice as explained further in Ms. Smith's testimony. The cost of raising these credits can be recovered through a higher Competitive Transition Charge (CTC), a longer recovery period for the CTC, lower rate reductions or some combination of these three. In conclusion, the Commission should not sacrifice the goal of having a competitive market for guaranteed rate reductions.

Q. If all of Staff's clarifications and modifications are not adopted by the Commission, does Staff believe the Commission should approve the Settlement as proposed?

A. Yes, however Staff has reservations as to the Settlement's impact on competition, particularly during the transition period provided for the recovery of stranded cost. Once stranded cost is fully recovered by APS, the basis for approval of the Settlement becomes more compelling. In other words, when stranded cost is collected, the value of the certainty and known path to competition reflected in the Settlement is increased.

Q. Does this conclude your testimony?

A. Yes it does.

EXHIBIT RTW-1

Staff's recommended conditions and limitations for waivers under the following Affiliated Interest Rules:

- **R14-2-801(5)**

  APS has requested a waiver of the definition of "reorganization" to exclude corporate reorganizations that do not involve a reconfiguration of the UDC in the holding company structure. Under the waiver proposed by APS, the holding company would be free to reorganize, buy or sell non-regulated affiliates without Commission approval. The Commission agrees that R14-2-801(5) is waived as applied to APS' non-regulated affiliates to the extent that the UDC is not implicated in any reorganization of the holding company's structure or the non-regulated affiliates' structure. In any reorganization where the UDC is implicated in any manner as to reconfiguration of the holding company's structure or an affiliates' reconfiguration, or if the UDC forms, divests or reconfigures any of its subsidiaries, Rule R14-2-801(5) is not waived and is applicable to APS (UDC).

- **R14-2-804(A)**

  APS has requested a waiver of the rule that requires any affiliate that transacts business with the UDC to open its books and records to Commission review. The Commission agrees that R14-2-804(A) may be waived as long as the non-regulated affiliate's books and records reflect transactions with the UDC and are included in the Code of Conduct required by the Electric Competition Rules. By this waiver, the Commission still retains jurisdiction to review and have access to the books and records of affiliates of the UDC for whatever purposes the Commission deems appropriate if the Commission's rate setting jurisdiction is implicated.

- **R14-2-805(A)**

  APS has requested waiver of the rule that requires a holding company to file an annual report with respect to diversification plans and the activities of unregulated subsidiaries. The affect of the waiver requested by APS would be to limit the annual filing requirement to the UDC only. The Commission agrees that the annual filing under the rule can be limited to the UDC unless the holding company or subsidiary's activities implicate the UDC, and have a likely material adverse affect upon the UDC's financial viability and integrity.

- **R14-2-805(A)(2)**

  This Rule requires a specific description of business activities of all affiliates to be filed with the Commission on an annual basis. APS wishes to have a waiver of the Rule and limit disclosure to the nature of the business rather than specific activities. Staff agrees this Rule may be waived to the extent indicated by APS.

- **R14-2-805(A)(6)**

  APS seeks a waiver of the disclosure requirement in the annual filing for bases for allocation of all plant revenue expenses to all regulated and unregulated entities in the holding company structure. APS' request limits disclosure to allocations applicable to the UDC. Staff agrees with this waiver to disclosure but reserves the Commission's jurisdiction to receive disclosure of the bases for allocation if necessary in the Commission's determinations in any matter, including but not limited to rate setting matters.

- **R14-2-805(A)(9), (10) and (11)**

  APS seeks a waiver of the annual submission of contracts and agreements for transactions between the regulated utility and nonregulated affiliate. Staff agrees to the waiver of this requirement as requested by APS as to the contracts and agreements which are not covered by the Code of Conduct required by the Retail Competition Rules or not subject to FERC approval. However, the Commission reserves the jurisdiction to receive the information that would have been submitted under the rule, if the Commission deems necessary for any purpose including, but not limited to rate setting matters.

EXHIBIT RTW-2

RAY T. WILLIAMSON

STATEMENT OF PROFESSIONAL QUALIFICATIONS

EDUCATION:

M.B.A. (Finance)	Arizona State University, Tempe, AZ, 1982
M.P.S. (Public Administration)	Western Kentucky University, Bowling Green, KY, 1976
B.S. (Engineering)	U.S. Military Academy, West Point, NY, 1970

PROFESSIONAL DESIGNATIONS:

Certified Energy Manager (CEM), Association of Energy Engineers, 1984

CURRENT PROFESSIONAL ACTIVITIES:

- Chairman, Solar Electricity Division, American Solar Energy Society
- Member, Association of Energy Engineers
- Member, International Association for Energy Economics
- Member, American Solar Energy Society

PAST PROFESSIONAL ACTIVITIES:

- Member, Board of Directors, Solar Rating & Certification Corporation (SRCC), 1988-91; Treasurer, 1989; Secretary, 1990
- Member, Rating Methodology Committee of SRCC, 1981-84
- Member, Arizona Photovoltaic Applications Task Force, 1985-86
- Participant, Arizona Energy Policy & Plan Development, 1989-90
- State Representative, Western Regional Biomass Energy Program, 1988-91
- Member, Arizona Electric Vehicle Task Force, 1991-92
- Member, Executive Committee, Interstate Solar Coordination Council, 1991-92
- Member, Externalities Task Force of the Arizona Corporation Commission, 1992
- Member, Environmental Technology Industry Cluster, Governor's Strategic Partnership for Economic Development (GSPED), 1992
- Member, Executive Committee, Interstate Renewable Energy Council, 1994-95
- Member, National Photovoltaics for Utilities Steering Committee, 1994-95
- Ex Officio Member, Planning Committee, Southwest Regional Transmission Association (SWRTA)

TEAM LEADERSHIP AND COMMITTEE COORDINATION EXPERIENCE:

- Coordinator, Arizona Electric System Reliability and Safety Working Group, 1996-98
- Coordinator, Arizona Photovoltaics for Utilities Cooperative, 1993-present
- Co-founder & Coordinator, Arizona Electric Vehicle Enterprise Network, 1990-92
- Founder & Chairman, Air Quality/Alternative Fuels Task Force of Phoenix Futures Forum, 1990-1992
- Coordinator, Externalities Prioritization Working Group, 1993-4
- Coordinator, Arizona Renewables Working Group, 1994-95
- Leader, Energy Efficiency & Environment Task Force, Retail Electric Competition Working Group, 1994-95

PROFESSIONAL EXPERIENCE:

ARIZONA CORPORATION COMMISSION, PHOENIX, AZ (OCT '92 - PRESENT)

ACTING DIRECTOR, UTILITIES DIVISION, MAR '98-PRESENT:

- Manages the 95-person Utilities Division
- Directly supervises five Section Chiefs, two Supervisors, and an Assistant Director

CHIEF, ECONOMICS AND RESEARCH, JUNE '97 –MAR '98:

- Managed the Economics and Research Section of the Utilities Division
- Supervised a staff of seven professionals
- Read, reviewed, edited, and approved tariffs, special contracts and other Commission Open Meeting items
- Prepared testimony for lawsuits regarding Retail Electric Competition
- Coordinated the Electric System Reliability and Safety Working Group
- Coordinated the Solar Portfolio Standard Subcommittee
- Staffed the Unbundled Services and Standard Offer Working Group
- Staffed the Independent System Operator and Spot Market Development Working Group
- Coordinated the overall Retail Electric Competition effort for the Division
- Wrote, edited, and published the Solar Portfolio Standard Subcommittee's final report
- Co-wrote, edited, and published the Unbundled Services and Standard Offer Working Group's final report
- From 12/15/97-2/6/98 performed duties of Acting Director for four weeks while Director was out of the country

SENIOR RATE ANALYST, MAY '94 - JUNE '97:

- Specialized in electric utility regulation activities and projects, including integrated resource planning, externalities, renewable energy resources, retail electric competition, and electric tariff review and evaluation
- Evaluated and developed recommendations on utility renewable energy plans and projects
- Served as the group leader of the Arizona Photovoltaics for Utilities Cooperative
- Coordinated the activities of the collaborative Renewables Working Group
- Wrote draft Commission rules for externalities and integrated resource planning
- Served as the Task Force Leader of the Energy Efficiency and Environment Task Force in the Retail Electric Competition Working Group
- Helped draft proposed Commission Retail Electric Competition Rules
- Participated as a member of the Planning Committee of the Southwest Regional Transmission Association
- Acted as the Coordinator of Arizona's Electric System Reliability and Safety Working Group

ECONOMIST, OCT '92 - MAY 94:

- Conducted economic and policy analyses of electric and telecommunications utility issues
- Analyzed applications of utilities regarding rate levels, rate design, and service offerings
- Prepared recommendations and testimony on renewable energy, energy conservation, demand-side management, integrated resource planning, special rates and contracts, and tariff filings
- Served as the Coordinator of the Arizona Photovoltaics for Utilities Cooperative
- Served as the Coordinator of the Externalities Prioritization Working Group
- Wrote, edited, and published the Externalities Prioritization Working Group's final report

ARIZONA DEPARTMENT OF COMMERCE, PHOENIX, AZ (JULY '85 - OCT '92)

ENERGY BUSINESS TECHNICAL SPECIALIST in the **ARIZONA ENERGY OFFICE**, MARCH '90 - OCT '92:

- Prepared testimony and testified as an expert witness in the first cycle of the Corporation Commission's Integrated Resource Planning. The testimony resulted in the formation of two Commission Task Forces to consider externalities and sliding-scale hook-up fees.
- Participated in the two-year Arizona Energy Policy and Plan development program
- Founded the collaborative Arizona Photovoltaics for Utilities Cooperative and coordinated its activities

MANAGER of the **ARIZONA SOLAR ENERGY OFFICE**, JULY '87 - MARCH '90:

- Managed the entire solar energy program for the State of Arizona
- Managed the accomplishments of a staff of eight employees and numerous contractors and subcontractors

ENERGY ECONOMIC ANALYST of the **ARIZONA ENERGY OFFICE**, JULY '85 - JUNE '87:

- Prepared various economic analyses, including the impact of the 1986 oil price decline
- Performed utility rate analyses and presented utility bill seminars to school officials and local governments
- Served on the Arizona Photovoltaic Applications Task Force established to evaluate the potential for the use of photovoltaics in Arizona and to make recommendations to the Arizona Corporation Commission

ARIZONA SOLAR ENERGY COMMISSION, PHOENIX, AZ (DEC '80 - JUNE '85)

ASSOCIATE DIRECTOR, FEDERAL PROGRAMS MANAGER, & SOLAR ENGINEERING SPECIALIST:

- Developed strategies and marketing plans to enhance the commercialization of solar energy products
- Was responsible for revising, drafting, staffing, and coordinating work on Commission rules and the public hearings on rules

RAMADA ENERGY SYSTEMS, INC., TEMPE, AZ (JUNE '79 - JULY '80)

MANAGER, MARKETING SERVICES:

- Managed all services and support of the Marketing Department and of the company distribution network
- Established office administration programs, developed standard operating procedures for the Marketing Department, and initiated a comprehensive national inquiry response program
- Developed and implemented advertising, publicity and public awareness plans

SOLARON CORPORATION, DENVER, CO (JULY '76 - JUNE '79)

FEDERAL PROGRAMS ADMINISTRATOR, AUG '78 - JUNE '79:

- Managed all activities of the federal solar grant programs
- Wrote grant applications, assisted applicants with design and grant preparation, follow-up reporting, and assistance on winning grants

ASSISTANT TO THE MANAGER, DISTRIBUTOR SALES, SEP '77 - JUL '78:

- Responsible for the day-to-day activities of the distributor network for Solaron products
- Developed marketing plans for the distributor network
- Assisted distributors in project design, computer simulation, and equipment selection

MARKETING ADMINISTRATOR, JUL '76 - AUG '77:

- Coordinated office administration
- Provided training and grant application preparation assistance to customers in federal grant programs. Sales through these grant programs accounted for 26 percent of all 1977 Solaron sales
- Served as a sales engineer, designing and selling individual systems in areas without distributors and sales to walk-in customers

U.S. ARMY EXPERIENCE: Commissioned Officer from June 1970-January 1976

ADDITIONAL TRAINING:

1984-1993 Arizona State University, College of Business: 36 semester hours of economics courses. This included course work in public utility economics & finance.

1976-1996 Attendance at 110+ seminars, conferences and workshops covering subjects such as: electric industry restructuring, energy conservation, demand-side management, thermal storage, energy economics, financing of energy projects, cogeneration, solar energy, integrated resource planning, solar energy in utilities, environmental concerns, electric vehicles, biomass, and energy-conserving building design.

PUBLICATIONS

Williamson, Ray T. "The Versatile Transparent Polymer Collector." Paper presented at the 1980 Annual Meeting of the International Solar Energy Society, Phoenix, Arizona.

Williamson, Ray T. **Standards for Solar Devices**. Arizona Solar Energy Commission, May 1981.

Williamson, Ray T., Editor. **Information Sources for the Solar Industry**. Arizona Solar Energy Commission, May 1981.

Williamson, Ray T., Editor. **Licensing Solar Contractors in Arizona**. Arizona Solar Energy Commission, May 1981.

Williamson, Ray T., Editor. **Arizona's Solar Laws & Rules**. Arizona Solar Energy Commission, May 1981.

Williamson, Ray T., Editor. **Arizona's Solar Energy Tax Credits**. Arizona Solar Energy Commission, May 1981. "Standards for Solar Collectors." Arizona Solar Energy Commission, March 1982.

Williamson, Ray T. "Tax Credits for Photovoltaic Devices." Arizona Solar Energy Commission, March 1983.

Williamson, Ray T. **Standards for Solar Energy Devices in Arizona**. Arizona Solar Energy Commission, May 1983. "Standards for System Testing." AZ Solar Energy Commission, June 1983.

Williamson, Ray T., Richard Griswold and Frank Mancini. "Solar Energy Response Vehicle (SERV) Meets Emergency Needs." Paper presented at the 1991 Solar World Congress. **Proceedings of the Biennial Congress of the International Solar Energy Society**, Denver, Colorado, 19-23 August 1991.

EXHIBIT RTW-2

Williamson, Ray T., Doran Dalton and Robert Robin. "The Hopi Foundation's Solar Electric Enterprise: A Model for Renewable Industry Development in Developing Nations." Paper presented at the 1991 Solar Word Congress. **Proceedings of the Biennial Congress of the International Solar Energy Society**, Denver, Colorado, 19-23 August 1991.

Williamson, Ray T., Peter Eckert, Tom Lepley, and Frank Mancini. "Testing and Evaluation of a Mobile Photovoltaic/Genset Hybrid System." Paper presented at the 22nd IEEE Photovoltaic Specialist Conference. **Proceedings of the 22nd Institute of Electrical and Electronics Engineers, Inc. Photovoltaic Specialists Conference**, Las Vegas, Nevada, 7-11 October 1991.

Williamson, Ray T., Editor/Co-author, and Robert Hammond, Frank Mancini, and James Arwood. "The Solar Electric Option (Instead of Power Line Extension)." A 16-page brochure published by the Arizona Corporation Commission and the Arizona Department of Commerce. Phoenix, Arizona, August 1993.

Williamson, Ray T., Co-author, and Staff of Economics & Research Section, Arizona Corporation Commission. "Staff Report on Resource Planning." Arizona Corporation Commission, September 1993.

Williamson, Ray T. "Staff Report on Arizona Public Service Company's Carol Spring Mountain Project," (DocketNo. U-1345-94-335), Arizona Corporation Commission, October 1994.

Williamson, Ray T., and Robert Gray. "Staff Report on Arizona Public Service Company's Photovoltaic Applications and Systems Development Program," (Docket No. U-1345-95-323), Arizona Corporation Commission, August 1995.

Williamson, Ray T., Co-author, and Staff of Economics & Research Section, Arizona Corporation Commission. "The Electric Industry In Arizona: Staff Report on Resource Planning." Arizona Corporation Commission, October 1996.

Williamson, Ray T., David Berry, and Kim Clark of Economics & Research Section, Arizona Corporation Commission. "Staff Discussion of the Proposed Rule on Electric Industry Restructuring," (Docket No. U-0000-94-165), Arizona Corporation Commission, October 1996.

Williamson, Ray T., "Incorporating Solar in a Restructured Electric Utility Industry," **Proceedings of the 1997 Annual Conference of the American Solar Energy Society**, Washington, D.C., 25-30 April 1997.

Williamson, Ray T. and David Berry, "Solar Power and Retail Electric Competition in Arizona," **Solar Today**, Vol. 11, No. 2, March/April 1997.

Williamson, Ray T. "Designing an Effective Solar Portfolio Standard," **Proceedings of the SOLAR '98 Conference**, American Solar Energy Society, Albuquerque, N.M., 13-18 June 1998.

Williamson, Ray T. and Howard Wenger, "Solar Portfolio Standard Analysis," **Proceedings of the SOLAR '98 Conference**, American Solar Energy Society, Albuquerque, N.M., 13-18 June 1998.

EXHIBIT
Admitted
5-2

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 ET SEQ.	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. RE-00000C-94-0165

DIRECT

TESTIMONY

OF

LEE SMITH

CONSULTANT

LA CAPRA ASSOCIATES
BOSTON, MASSACHUSETTS

JUNE 30, 1999

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EXHIBITS

APPENDICES

INTRODUCTION

Q. What is your name and business address?

A. My name is Lee Smith, and I work for La Capra Associates, 333 Washington Street, Boston, Massachusetts.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Arizona Corporation Commission (Commission) Staff.

Q. Please describe your background and experience.

A. I am a Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 15 years. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level. My resume is attached as Exhibit LS-1.

Q. What is the purpose of your testimony?

A. I am testifying as to the concepts in the 10 Page Settlement Agreement between Arizona Public Service Company ("APS" or "Company") and the Residential Utility Consumer Office ("RUCO"), Arizona Community Action Association ("ACAA"), and Arizonans for Electric Choice in Competition ("AECC") excluding Enron ("Proposed Settlement").

Q. Have you submitted testimony previously in this proceeding?

A. Yes. I submitted testimony on the proposed November 4, 1998 Settlement between APS and the Commission Staff which was subsequently withdrawn ("November Settlement").

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Q. What major changes should be made in the regulation and organization of the electric industry to foster the development of a competitive electric services market?

A. In order to have competition in electric services, the following must occur

- assurance that all potential suppliers have fair access to customers;
- assurance that all potential suppliers have fair access to the wires;
- the ability to identify and address market power in generation;
- customers must have the opportunity to purchase electric services from a supplier of their choice;
- customers must be informed of what they pay the utility for each service, so they can compare different providers;
- subsidization of unregulated services by regulated services must be avoided, otherwise the utility will have an unfair advantage over competitive suppliers; and
- disputes over stranded cost must be resolved.

Q. What criteria should be applied in considering approval of the APS settlement?

A. It is Staff's opinion that any settlement agreement presented to the Commission should be evaluated using the above-mentioned criteria. The Commission should apply criteria that measure whether the agreement contributes to the goals of allowing competition and providing benefits to Arizona consumers. An approved Settlement should facilitate the development of a competitive market in Arizona. That requires the characteristics described above. It should also provide all customers with some immediate benefits that they would not receive under a continuation of existing regulatory practices.

Q. Does the Proposed Settlement ensure that all potential suppliers have fair access to customers?

A. The Proposed Settlement is consistent with the Electric Competition Rules ("Rules") as they relate to providing fair access to customers by the Affected Utilities as reflected in Article VII, Section 7.7. The Commission will have the authority to ensure equal access by all potential suppliers to the customers through its approval of the Code of Conduct contemplated by the Rules and referred to in the Proposed Settlement at Article VII, Section 7.7. Based upon the foregoing, it is Staff's opinion that the Proposed Settlement adequately ensures that all potential suppliers will have fair access to customers.

Q. Does the Proposed Settlement ensure that all potential suppliers have fair access to the wires?

A. The support by APS of the Arizona Independent Scheduling Administrator (AISA) and of the formation of the Desert Star Independent System Operator (ISO) is an important step in providing fair access to the wires. However, as long as a single entity owns and controls transmission and owns generation there will be incentive for and possibility of limiting access of other suppliers to the wires.

Q. Does the Proposed Settlement enable the Commission to identify and address generation market power?

A. The Proposed Settlement requires that APS sell its generating assets to an affiliate at the net book value of those assets in 2002. I have some concerns about the continuing incentives for APS, as the only provider of transmission service, to favor standard offer power purchases or delivery of generation from an affiliate. In its recent FERC Notice of Proposed Inquiry regarding Regional Transmission Organizations ("RTO"), FERC expresses concerns that the existing utility-by-utility control of transmission is not efficient and may allow a transmission owner to favor its own generation, in spite of the rules about Open Access Transmission Tariffs established in FERC Order 888.

Q. What impact may the FERC proceeding have on the APS Proposed Settlement and the proposed transfer of generating assets to an affiliate?

A. In the time between now and when APS transfers its assets, FERC should have completed the RTO investigation, and there will have been adequate time for Desert Star or some other type of an RTO to be in operation or fully developed conceptually. I would recommend that the Commission's approval of the generation transfer in the Proposed Settlement be conditioned upon appropriate progress toward an RTO. The establishment of an RTO has the potential of greatly alleviating, if not eliminating, concerns about both vertical and horizontal market power.

Q. Does the Proposed Settlement provide customers the opportunity to purchase electric services from a supplier of their choice?

A. Article I of the Proposed Settlement, Implementation of Retail Access, addresses providing customers the opportunity to purchase electric services from a supplier of choice. The Proposed Settlement accelerates the implementation date and increases the eligible load from the amounts required in the Electric Competition Rules. Based upon the foregoing, it is Staff's opinion that the Proposed Settlement provides customers the opportunity to purchase electric services from a supplier of their choice.

Q. Does the Proposed Settlement inform customers what they pay the utility for each service, so they can compare different providers?

A. No. The Company has not unbundled its Standard Offer Service tariffs, and has not informed Direct Access customers how much they would have paid the Company for generation. In addition, the unbundled metering and billing credits in the Proposed Settlement do not reflect the embedded cost that a customer is currently paying for these services.

Q. Does the Proposed Settlement contain adequate safeguards to avoid the subsidization of unregulated services by regulated services, so as to avoid giving the utility an unfair advantage over competitive suppliers?

A. Consistent with the Electric Competition Rules, the Proposed Settlement contemplates the filing of a Company-specific code of conduct. The Code of Conduct is subject to the

Commission's approval of terms that should establish procedures to eliminate the potential for the subsidization of unregulated services by regulated services. Based upon the foregoing, it is Staff's opinion that the Proposed Settlement contains appropriate language to allow the Commission to approve a Code of Conduct, consistent with the Rules, to provide adequate safeguards to avoid the subsidization of unregulated services by regulated services, so as to avoid giving the utility an unfair advantage over competitive suppliers.

Q. Does the Proposed Settlement resolve disputes over stranded cost?

A. The Proposed Settlement attempts to resolve disputes over stranded costs.

Q. Please explain how the Settlement attempts to resolve the issue of stranded costs.

A. The Proposed Settlement at Article III - Regulatory Assets and Stranded Costs provides a quantification of stranded costs and establishes a recovery mechanism for a portion of the amount determined. It contains an assertion that allowable stranded costs are at least $533 million after mitigation (Section 3.2).

Q. Do you agree with this assertion about the value of stranded costs?

A. No. Mr. Davis cites Exhibit 2, presented to the Commission in this docket at Exhibit JED-3. This exhibit most certainly does not reflect a full and fair evaluation of stranded costs. It compares market revenues to embedded generation costs for the six years commencing in 1998 and ending in 2004.

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DETAILED DISCUSSION OF SPECIFIC PROBLEMS WITH CRITERIA

Q. Of your recommended criteria to be used by the Commission in evaluating a settlement associated with competition in electric services, you have identified two which are not fully met by the Proposed Settlement: 1) informing customers what they pay the utility for each service, so they can compare different providers, and 2) resolving disputes over stranded costs. Would you please explain more precisely why you believe the first of these criteria have not been met.

A. Yes. The Company has not provided rates which unbundle the existing tariffs. With regard to metering and billing services, if a customer chooses an alternate supplier of metering or billing services or both, the Company proposes to provide credits to the bill. These credits are based on APS' avoided costs only. They reflect decremental costs associated with these services, but do not include all embedded costs.

Q. What alternative would be consistent with the criteria?

A. The Company calculated and offered rates in the November Settlement based on its unbundled cost of service study. The credits were significantly higher than the avoided cost credits in this Proposed Settlement. For instance, for Residential customers the billing credit was $1.33 per month, while in the Proposed Settlement the billing credit is only $.30 per month. For Extra-large General Service customers, the embedded metering credit was $154.15 per month, while the avoided cost credit proposed in the Proposed Settlement is only $55 per month. The Company should file rates based upon the embedded costs unbundled into functional components.

Q. Would you explain how the use of avoided costs versus embedded costs will inhibit the development of a competitive market for metering and billing services?

A. Yes. The Company is currently collecting revenues from ratepayers based on the embedded costs of all services, including metering and billing. However, if the customer does not use these services, the Company is proposing to reduce bills by a much smaller amount than what was collected in their current rates. This means that customers who choose alternative suppliers will continue paying for some portion of the Company's metering and billing costs. This type of pricing is also anti-competitive, in that new providers will find it difficult, if not impossible, to provide these services at a competitive rate. To take a specific example, the decremental cost rate, as proposed in the Proposed Settlement, would not include the cost of the meter reader's truck or any overhead. These expenses would be supported by the remaining distribution portion of the rate, while the new competitor would need trucks and overhead and have to recover these from his price.

Q. Are there any other ways in which the Proposed Settlement rates do not fully inform customers about their rates?

A. Yes. For each customer class, the Company provides one (or more) bundled Standard Offer Service tariff, which does not show separate functional rate components (generation, transmission, distribution, etc.), and one Direct Access tariff, which is unbundled into distribution service and Competitive Transition Charge ("CTC") components, but not generation or transmission.

Q. Can you explain why the unbundling of the Standard Offer Service tariffs to provide this level of detailed information is important to the development of a competitive market?

A. To make an informed decision about competitive service alternatives, customers must know what credit they will receive if they shop for generation, as well as metering and billing services, and those credits must be high enough so that some suppliers can compete with them. The Company's tariff does not inform customers of the market generation credit ("MGC") or the amount of transmission costs that they pay on Standard Offer service.[1] Customers will know the tariff rates that they will pay for bundled

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[1] The rate reduction that customers receive for not buying generation is usually called the Market Generation Credit, or MGC.

service, and they will know the direct access tariff rates that they will pay if they choose an alternative supplier. However, they must compute the difference between the two in order to know what generation and transmission revenue target they must beat. This is not an easy comparison, and it differs for every customer. Without the ability to isolate the portion of the customer's bill associated with these services, an informed choice can not be made. It is imperative that the Company be required by the Commission to fully unbundle its Standard Offer Services tariffs and Direct Access tariff to the same level of detail to allow this comparison.

Q. What impact do you expect this lack of a transparent market generation credit will have on competition?

A. I expect that it will have a deleterious effect. The largest customers may make these computations, or marketers may make these computations for them, but it will be difficult for smaller customers to shop. The smaller customer, receiving information that an alternative supplier can provide power for twelve months for a price of x, does not know whether the average price he is paying for power is more or less than x. To make this determination, the customer will have to have available his billing history for the last twelve months, or project his bill determinants for the next year, and determine what his bill would be under two separate rate schedules, involving seasonal differentials, an energy block (or more complicated time-of-use blocks), and a change in the basic customer charge.

Q. Are there any other side effects of this "two rates per class" system?

A. Yes. The rate reductions to customers who choose will be different than the reductions to customers who do not choose. In some cases the reductions to choice customers will be greater than to bundled service customers.

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Q. How did you calculate the Company's proposed MGC for various classes?

A. The credit that Direct Access customers will receive for generation is the difference between the two sets of rates, the Standard Offer Service Tariff and the Direct Access Rate for their rate class. We have calculated the effective MGC from the Proposed Settlement rates for 1999-2000 to be approximately 3.0 cents for the Extra-Large General class, 4.1 cents for the General Service class, and 4.5 cents for the Residential class. The backup to the MGC calculations is attached to my testimony as Exhibit LS-2.

Q. Is this credit sufficiently large that alternative suppliers will be able to compete effectively with APS?

A. No. If an alternative supplier must pay more for generation, transmission, and required ancillary services than the credit which the customer will receive from the utility, we would expect that there would be very little if any competition. The supplier cannot compete if the price of his supply is higher than the credit that potential customers receive from APS.

Q. What market price measure have you examined to come to this conclusion?

A. Unfortunately, there is no single easily available reference price. We have estimated the wholesale market price from price information from the spot market in California. That estimation process is described in Appendix A. We estimate that the average wholesale market price for the last year has been 2.9 cents per kWh. To get power to the customer will also require accounting for line losses. In addition, the supplier must acquire ancillary services and transmission. This suggests that for a retail customer to have purchased all <u>predicted</u> energy needs from the California spot market, with minimum transmission costs and paying APS only for ancillary services and transmission, would have cost at least 3.4 cents per kWh for the Extra-Large General Service class, and considerably more for other classes.[2] I would expect that the price for 1999-2000 would

[2] For transmission prices, I have used the transmission rates in proposed tariffs submitted by APS in the November Settlement.

be slightly higher than this. However, I also expect that the actual retail market price of power will be still higher than the barebones spot market price.

Q. Please describe the other elements of market price.

A. First, customers, or their suppliers, must pay for "load balancing," risk of price variation, customer service, and some profit. These elements must be added to the wholesale price to determine what retail prices will be including a return on generating plant, and are probably buried in stranded costs. I believe a conservative estimate of retail prices would be 4.6 cents for Residential customers, 4.23 cents for General Service customers, and 3.45 cents for Extra-Large General Service customers. A more detailed discussion of these costs is contained in Appendix B.

Q. Might these be high measures of retail market price?

A. No. In fact, I believe it will be very difficult for alternative suppliers to match this price. This does not include any marketing or startup costs.

Q. The MGCs for the Residential class are much higher than for the Extra-Large General Service class. Are these credits likely to create competition for generation needs of the residential class?

A. No. First, the retail market price for the Residential class will be much higher for the residential class than for the Extra-Large General Service class, because of line losses, and load shape. Second, the residential market seems to be much less attractive to marketers than the large customer classes. Finally, only ten percent of the residential class will even be eligible for access, so the potential market is limited for two years.

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Q. Mr. Higgins testified that he expects that the MGC will be higher than the market price by about 5 mills, "for commercial customers". Why is his conclusion so different than yours?

A. Mr. Higgins is referring to a particular customer in the General Service class. Also, he is comparing the MGC to a wholesale price for absolutely flat load - in other words for a customer that used exactly the same kWhs every hour of every month. The customer for whom Mr. Higgins has calculated the commercial market generation credit does not have a flat load, since he has specified that this is a 55 percent load factor customer according to Response to Data Request LS-1. Recognizing that the wholesale price will be higher because of the customer's load shape would decrease the market generation credit.

Q. You stated earlier that you disagreed with the Company's assessment of its stranded costs. Do you agree with the market prices used by the Company in their stranded cost analysis?

A. No. They are too low by about 2 mills. We know that spot prices at Palo Verde for the eleven months from July 1998 through April 1999 were 2 mills, or 7 percent, higher than the prices used in the Company's stranded cost analysis for 1999. Moreover, the Company's generating units also earn revenue through the provision of ancillary services. That is, they sell not only energy but also ancillary services, which will produce additional revenues. Thus, the average revenue earned by the Company's generating units will be higher than the average wholesale price.

Q. Are there problems with the Company's analysis other than with the level of market prices projected?

A. Yes. The major problem is methodological. Even if the estimates of both market revenues and embedded costs were correct, the Company's presentation does not measure stranded costs. This methodology fails to reflect the true difference between market value and embedded costs.

Q. Why is this an incorrect method of measuring stranded costs?

A. The assets in question will continue to have value for longer than six years; in fact, most of the generating assets will continue in production for another ten to twenty years. As time passes, market prices increase, while embedded costs stay almost the same. Even the Company's brief analysis shows market prices increasing 6 mills as embedded costs increase by 1 mill. As a result, there will be a crossover point when these units produce market revenues in excess of embedded costs. From then on, the annual measurement of stranded cost will be negative. By stopping the analysis after six years, this methodology fails to account for future negative stranded costs.

The Company's witness, Mr. Landon, argues that stranded costs would actually be higher if the analysis encompassed more years. The test of this proposition would be for the Company to show their estimates of market and embedded prices in the long run. In response to discovery, the Company states that its estimates of market prices reach their embedded costs after 2008. Since the 1998 estimates showed market prices about 1 cent less than embedded costs, this indicates that market prices are projected to increase relative to embedded costs over the next 10 years. If this trend continues, it is clear that embedded costs will fall below market prices.

Q. Why do you expect market prices of generation to increase?

A. I expect that fuel prices will increase over time. Although there is considerable variation in fuel price projections, all of the forecasts that I have seen project that fuel prices will, in general, increase over time. Environmental rules are likely to increase generation prices, through requiring higher quality fuel or more expensive treatment of emissions. In addition, growth in energy demand is likely to mean more production by higher energy cost generating units.

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The capacity cost associated with generation is also likely to go up, as materials and labor costs increase. There has been an improvement in technology, which reduced capital costs, but it is not at all clear that capital costs can be continually decreasing. In fact, some of the apparent reduction in capital cost was due to the market situation of the manufacturers of generators.

Q. Mr. Landon also argues that the Company's estimate of its stranded cost may be low because it has assumed "aggressive" capacity factors for its coal and nuclear plants. Do you agree?

A. While I have not analyzed the Company embedded price projections in detail, the numbers that I have seen do not support this position. Mr. Landon compared projected capacity factors with only a few historic years, one of which was affected by an extraordinary event. Most utilities across the country have been increasing capacity factors in recent years as they have been making efforts to reduce costs in order to participate in competitive markets.

In addition, the Company used similar capacity factors in its modeling of embedded and market price. If we accepted Mr. Landon's view that the actual capacity factors for nuclear units will be lower than those projected, then embedded costs will be higher but so also will market prices. If nuclear units produce less energy, more energy must be produced from coal, gas and oil units, pushing up market prices.

Q. Since you expect that annual stranded costs will decrease and will become negative, do you agree that the Company has demonstrated stranded costs of $533 million?

A. I do not agree that the Company has appropriately demonstrated its level of stranded costs. I also do not agree that APS' stranded costs are $533 million. I think the correct number is materially less than this amount.

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RECOMMENDED REMEDIES TO PROBLEMS IDENTIFIED

Q. Of your recommended criteria to be used by the Commission in evaluating a settlement associated with competition in electric services, what are your recommendations for resolving the unsatisfied criteria, particularly 1) informing customers what they pay the utility for each service, so they can compare different providers, and 2) resolving disputes over stranded costs?

A. First, the Company should be required to remove the embedded costs of metering and billing from the distribution component of the Direct Access rates and show these as separate avoidable charges. They should be similar if not identical to the metering and billing charges included in the November Settlement. To address the remainder of the unsatisfied criterion regarding informing customers what they pay the utility for each service, so they can compare different providers, Staff recommends that the Commission approve the Proposed Settlement with the modified condition that APS unbundle its Standard Offer Service, showing generation and transmission rates. In addition, APS should provide explicit information on Market Generation Credits (MGC) for the Residential, General Service, and Extra-large General Service Direct Access rates. As for the second unsatisfied criterion, resolving disputes over stranded costs, Staff is recommending a true-up mechanism to prevent the over-collection of stranded costs which might occur without such a mechanism.

Q. How else should the Proposed Settlement be modified to create the potential for competition?

A. In order to create a competitive market, the market generation credits, particularly for the class most likely to shop, the Extra-Large General Service class, must be increased. The minimum MGC must be higher than the spot price adjusted for ancillary services and line losses. If the MGC is higher, either total rates will increase or some other component of rates must decrease. If another component of rates decreases, either the collection period must be lengthened or the total collection of revenues will be less than planned with the original rates. To accomplish this and still abide by other conditions of the settlement, at least two adjustments must be made. First, some other component of rates must be decreased by an equal amount. The logical choice is the CTC. Second, with a lower CTC, it will take a longer transition period to collect the same amount of stranded costs.

Q. How should the MGCs and CTCs be adjusted?

A. The goal should be to provide the Company with the same revenue collection as currently proposed from each class from the combination of the MGC and the CTC. With the proposed residual rather than stated MGC, if the CTC for any class is increased by a particular amount, the MGC is automatically decreased by the same amount. Since the proposed MGCs are about 2 mills lower than my estimated retail market price, I recommended that the CTCs be decreased by an average of about 2 mills in 1999 and 2000, which will increase the MGC by the same amount. In future years, the Proposed Settlement reduces charges for Direct Access, so that the MGCs increase, but are still lower than they should be. The Table below shows the MGCs in the Proposed Settlement and the MGCs which I am recommending for each year of the transition period. Again, an increase in an MGC can be accommodated by an equal decrease in the proposed CTC.

MARKET GENERATION CREDIT IN CENTS PER KWH

	1999	**2000**	**2001**	**2002**	**2003**	**2004**
Residential Settlement	4.5	4.6	4.7	4.7	4.7	4.9
Residential - CC Staff	4.6	4.6	4.7	4.7	4.8	4.8
General Service Settlement	4.1	4.1	4.2	4.3	4.3	4.5
General Service - CC Staff	4.2	4.2	4.3	4.3	4.4	4.4
Extra-Large GS Settlement	3.0	3.0	3.2	3.2	3.3	3.5
Extra-Large GS - CC Staff	3.3	3.3	3.4	3.4	3.5	3.5

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Q. In light of your disagreement with the Company's stranded cost claim, do you recommend that the Commission disapprove the settlement?

A. No. The Proposed Settlement will allow the Company to collect a level of stranded costs of $350 million, which is significantly lower than the claimed $533 million. It also clearly is an advantage to settle this very controversial issue. I recommend that the Proposed Settlement be modified so as to address both the MGC and the stranded cost questions. If the Company does not sell its generating assets, which would reveal their value, the best indications we have about the validity of their stranded cost estimate are actual market prices. Also, the MGC should ideally be related to actual market prices. I suggest the following modifications.

Earlier I advocated that CTCs should be reduced so that the MGC could be increased. The impact of this on CTC collection should depend upon whether the agreed upon MGCs appear to be a fair measure of the actual market prices.

The Company may accumulate in a deferred account the revenues that would have been collected through the higher proposed CTC. To determine if the CTC should continue beyond December 31, 2004, and for how long, the Company should make a filing with the Commission on July 1, 2004. This filing shall demonstrate the amount of CTC revenues collected and projected to be collected by December 31, 2004, and the resulting deferred CTC amount. In addition, this filing should compare the actual wholesale market price in 2003-2004[3], to the wholesale market price used as a basis for the company's stranded cost estimate for that year. If this actual market price is lower than the projected wholesale market price by more than one mill, the Company shall be allowed to continue collecting a CTC until the deferred amount and the full $350 million

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[3] The wholesale price would be determined by the California spot market price, unless an alternative source of transparent market information has been developed by that time.

is collected. If the actual market price is higher than the MGC by more than one mill, the Company shall not be allowed to collect the deferred amount, but shall be allowed to retain all previous CTC revenues collected.

In this latter case, we would have clear evidence that market prices had been considerably higher than those projected by the Company. Higher than projected market prices would strongly suggest that the Company's generating assets had more value than the Company had previously assumed.

To illustrate why I am advocating this deferral and conditional collection, we can refer to the Company's stranded cost filing. In the table below, I show how stranded costs would decrease if, in the year 2003, wholesale market prices increase by 1 mill from those projected by the Company in their stranded cost filing.

gWhs	Comp. estimate wholesale price cents/kWh	Embedded cost	Stranded cost	Hypothetical Actual wholesale price	Revised Stranded cost
23,400	3.2	3.8	$129 million	3.3	$105 million

Q. What is your final recommendation to the Commission regarding this agreement?

A. I am recommending that the Commission approve the Proposed Settlement with the minor modifications discussed above which will make the Proposed Settlement more consistent with the goal of establishing a competitive market.

OTHER ISSUES

Q. Are there any other rate issues?

A. Yes. Article 2.6 would require the Commission to approve four automatic adjustment clauses. The first and second clauses address Standard Offer costs after the Company has sold its generating assets, and will allow the Company to pass on the cost of acquiring that power. However, the third and fourth clauses will allow the Company to increase rates for certain costs, associated with implementation of the Electric Competition Rules and system benefits, without demonstration that overall Company earnings are less than allowed. This creates a situation similar to what has been described as a single issue rate case. The adjustment clause might identify that the Company had spent $30 million on transition costs, but since the issue would be examined in isolation, if sales growth had been rapid or other expenses had not increased much, the Company might have been overearning by $20 or $40 million. The fairer solution for ratepayers would be to award the Company only the $10 million shortfall in the first case, or to decrease rates in the second case.

Q. How could the Proposed Settlement be modified to address this issue?

A. The Proposed Settlement does not contain these clauses, but rather specifies that the Company file a detailed application for these clauses by June 1, 2002. The Commission would examine these clauses and "issue an order that shall also establish reasonable procedures pursuant to which . . . parties . . . may review the costs to be recovered." Those reasonable procedures could include an annual filing requirement that demonstrates that, absent the deferral, the Company would earn less than its authorized rate of return. The Commission could approve the Proposed Settlement but specify that the specific adjustment clauses should be written to include the provision described above.

This is particularly necessary because other Proposed Settlement provisions provide protections to the Company but not to ratepayers. Article 2.8 allows the Company to request a rate change in the event of an emergency or material changes in cost resulting from any type of law or order. However, it also specifies that except for these specific changes, rates shall remain unchanged until July 1, 2004. In other words, the Company has the ability to increase rates but ratepayers do not have symmetrical rights; if the

Company is overearning, even significantly, no party will have the right to examine the Company's cost of service and request a rate decrease.

Q. The Company has indicated that the rate reductions in the Proposed Settlement are a great benefit to customers. Might these rate reductions be a significant enough benefit to justify the low MGCs?

A. No. Since a MGC that is too low will prevent the development of a competitive market for generation service, it will frustrate the entire purpose of the retail electric competition effort. In addition, the benefits have been greatly exaggerated.

Q. Why are 1.5 percent rate reductions for five years not a large benefit?

A. First, the size of the reductions, even cumulatively, are small relative to what utilities in other regions have provided after restructuring. Second, since the Company may increase its rates under certain conditions, and will be allowed to defer some costs for later collection, it is not clear that these guaranteed reductions leave customers in a better position than normal ratemaking might produce.

Q. What size reductions have customers received in other states?

A. In three states, Massachusetts, California, and Rhode Island, all customers have received reductions of 10 percent or more, while Maryland, New Jersey, and Delaware have mandated cuts of 3 percent, 5 percent, and 7.5 percent, respectively. Illinois, Kentucky, New Hampshire and Texas also appear to be providing more significant rate reductions than the Proposed Settlement's 1.5 percent reductions.

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Q. How might customers be better off as a result of the normal ratemaking process?

A. The rate adjustment mechanisms could result in increases that eliminate all or part of these reductions. Thus the reductions of 1.5 percent, which will result in total revenue reductions of about $25 million per year, could be followed by increases of $30 to $50 million. Normal ratemaking practice might have produced larger decreases, or might not allow revenue increases for these incremental costs.

Q. Is there any specific indication in this case of the rate reduction that might occur under normal ratemaking?

A. Yes. The Company has been providing customers with small rate decreases over the last four years that reflect faster growth in revenue than in costs. When revenues increase faster than costs, we would expect the Company to be overearning. However, the Company has given up only 55 percent of the "excess"[4]. This suggests that a full rate investigation now might well determine that the Company was overearning and result in a rate decrease. The Company cites 1998 as evidence that the automatic increase would have been less than the 1.5 percent decrease. However, the Company's own Form 10-K for 1998 filed with the Securities and Exchange Commission notes that its 1998 revenues were lower than normal by $33 million because of milder than normal weather. If sales had been higher, variable costs would also have increased, but fixed costs would not have changed. If normal weather had occurred, the revenue/cost comparison would have resulted in larger total overearnings. It appears likely that a rate case based on a normalized 1998 cost of service would result in rates being lowered by considerably more than the 1.5 percent reduction in the Proposed Settlement. Also, normal ratemaking practice would not allow an increase for the incremental transition costs referenced in the adjustment clauses if the Company was overearning by that amount or more.

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4 The exception is property tax decreases, of which 100 percent has gone to ratepayers.

Q. Are there any other problems with the rate provisions of the settlement?

A. The proposed Direct Access rates show a Competitive Transition Charge (CTC) which is a demand rate for the General Service class. Since some customers on this rate do not have demand meters, it would appear that they would not pay any CTC. If this is a correct interpretation of the rate, an energy based CTC should be added to apply only to customers without demand readings.

Finally, based on my MGC calculations, it appears that the Special Contract customers would receive a market generation credit of 3.5 cents. This would appear to provide them much more of an opportunity to shop for power than other customers on the Extra-Large General Service class whose MGC is just above 3 cents. This does not seem an appropriate result. It could also be construed as prior discrimination.

Q. Does this complete your direct testimony?

A. Yes, it does.

LEE SMITH

LA CAPRA ASSOCIATES
Senior Economist

Ms. Lee Smith is a Senior Economist at La Capra Associates. Ms. Smith has over fifteen years experience in utility economics and regulation. Her work has encompassed all aspects of utility pricing, cost analysis, forecasting, and both demand-side and supply planning in electric, gas, and water utility cases. As a consultant, her clients have included gas and electric utilities, regulatory commissions and other public bodies. Ms. Smith has advised the Massachusetts Division of Energy Resources on position on changes in Integrated Resource Management, including proposal to open Transmission and Distribution access to meet resource needs. Previous to La Capra Associates, Ms. Smith was employed as the Director of Rates and Research at the Department of Public Utilities.

ACCOMPLISHMENTS

- Assisting the Arizona Corporation Commission in developing unbundled rates for all Arizona utilities; preparing positions, and negotiating with utilities.
- Advised and provided testimony on rate unbundling for the Maryland Office of the Public Counsel for all utilities in Maryland in restructuring proceedings.
- Advised Pennsylvania Office of the Public Advocate staff in restructuring proceedings; presented testimony on rate unbundling in eight cases.
- Assisted Massachusetts Division of Energy Resources in drafting restructuring legislation and negotiating additional restructuring settlements with utilities.
- Assisted Commission staff in both electricity restructuring cases and utility requests for Qualified Rate Orders allowing securitization of some stranded costs for the Pennsylvania Office of the Consumer Advocate.
- Assisted New Hampshire Public Utilities Commission staff in writing Draft Order on Restructuring; prepared discovery for utilities; prepared discovery questions for hearings on various issues, including corporate unbundling, market structure, transmission, stranded cost theory, measurement, and mitigation.
- Assisted DOER in all aspects of electric industry restructuring from rate unbundling to planning and developing revised market structure for the New England Power Pool.

- Represented the DOER at NEPOOL committees engaged in developing an Independent System Operator, a revised NEPOOL Agreement, and an Open Access Transmission Tariff for New England. Assisted the DOER in other matters including development of model for Boston Edison pilot program based on proxy for competitive market real-time pricing.

- Prepared alternative marginal cost study on Maine Public Service Company. Presented testimony advocating allocation of excess costs on the basis of generation allocators rather than EPMC.

- Prepared testimony on cost allocation and rate design for local gas distribution utility for Kansas Citizens' Utility Ratepayers Board. Assisted in settlement negotiations.

- Testified for Massachusetts Municipal Wholesale Electric Company on appropriate allocation of gas transition costs; assisted MMWEC in formulating response to generic docket on interruptible gas transportation; prepared comments.

EMPLOYMENT

Department of Public Utilities:
Director of Rates and Research,
1982 - 1984

EDUCATION

Ph.D., all but dissertation, Tufts University, Economics
B.A., Honors, Brown University,
International Relations and Economics
Study of Statistics, Boston College

HONORS

Bunting Institute Fellowship, 1970-71
Tufts University Economics Department Fellowship, 1967-68
Prize in International Relations, Brown University, 1965

Residential Service: Year 1 (1999)

New Direct Access Rate
May - October

	flat	per kWh	
Basic Service Charge	10.00		
Original	7.50		
Incremental Cust. Chg.	2.50	0.00212	
Distribution		0.04158	
SBC		0.00115	
CTC		0.00930	
sum		0.05415	

November - April

	flat	per kWh
Basic Service Charge	10.00	
Original	7.50	
Incremental Cust. Chg.	2.50	0.00316
Distribution		0.03518
SBC		0.00115
CTC		0.00930
sum		0.04879

Old Unbundled Rate
May - October

	flat	per kWh			Weighted kWh
Basic Service Charge	7.50	0.08028	first 400 kWh		0.02498
		0.11191	next 400 kWh		0.02557
		0.13051	all additional kWh		0.06008
			sum		0.11063
Revenues	$27,514,672.50	$479,531,909.59	$ 507,046,582.09		
		$ 0.1106	average summer		

November - April

	flat	per kWh	
Basic Service Charge	7.50		
		0.08047	
Revenues	$ 27,547,912.50	$233,598,545.02	$261,146,457.52

Calculation of New Discounted Standard Offer Rate
May - October

Discounted Revenues			$ 499,440,883.36
Difference			$ 7,605,698.73
New Revenue Stream	$27,514,672.50	$471,926,210.86	$ 499,440,883.36
SO Discounted Rate*	7.50	0.10887	

Calculation of New Discounted Standard Offer Rate
November - April

Discounted Revenues			$257,229,260.66
Difference			$ 3,917,196.86
New Revenue Stream	$ 27,547,912.50	$229,681,348.16	$257,229,260.66
SO Discounted Rate*	7.50	0.07912	

Difference between Standard Offer and direct access rates
May - October

SO Rate		7.50	0.10887
direct access rate		7.50	0.05415
Difference		**0.00**	**0.054729016**
Annual Generation Credit	**TOTAL $**		**$237,226,866.17**
	per kWh		**0.055**
Weighted Average	**per kWh**		**0.0449**

November - April

SO Rate		7.50	0.07912
direct access rate		7.50	0.04879
		0.00	**0.030327371**
	TOTAL $		**$ 88,038,146.36**
	per kWh		**0.030**

* Assume reduction flows through energy charge.

Residential Service: Year 2 (2000)

New Direct Access Rate

May - October

	flat	per kWh
Basic Service Charge	10.00	
Original	7.50	
Incremental Cust. Chg.	2.50	0.00212
Distribution		0.04041
SBC		0.00115
CTC		0.00840
sum		0.05208

November - April

Basic Service Charge	10.00	
Original	7.50	
Incremental Cust. Chg.	2.50	0.00316
Distribution		0.03419
SBC		0.00115
CTC		0.00840
sum		0.04690

Calculation of New Discounted Standard Offer Rate

May - October

Discounted Revenues			$ 491,949,270.11	
Difference			$ 15,097,311.98	$ 7,491,613.25
New Revenue Stream	$27,514,672.50	$464,434,597.61	$ 491,949,270.11	$464,434,597.61
SO Discounted Rate*	7.50	0.10715		

Calculation of New Discounted Standard Offer Rate

November - April

Discounted Revenues			$253,370,821.75
Difference			$ 7,775,635.77
New Revenue Stream	$ 27,547,912.50	$225,822,909.25	$253,370,821.75
SO Discounted Rate*	7.50	0.07779	

Difference between Standard Offer and direct access rates

May - October

SO Rate		7.50	0.10847
Direct Access		7.50000	0.05208
Difference		-	**0.05639**
Seasonal Generation Credit	**TOTAL $**		**$244,444,257.01**
	per kWh		**0.056**
Weighted Average	**per kWh**		**0.0462**

November - April

SO Rate		7.50	0.07779
Direct Access		7.50	0.04690
		-	**0.03089**
	TOTAL $		**$ 89,666,239.70**
	per kWh		**0.031**

* Assume reduction flows through energy charge.

Residential Service: Year 3 (2001)

New Direct Access Rate

May - October	flat	per kWh		
Basic Service Charge		10.00		
Original		7.50		
Incremental Cust. Chg.		2.50	0.00212	
Distribution			0.03934	
SBC			0.00115	
CTC			0.00630	
	sum		0.04891	

November - April	flat	per kWh	
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00316
Distribution			0.03329
SBC			0.00115
CTC			0.00630
	sum		0.04390

Calculation of New Discounted Standard Offer Rate

May - October				
Discounted Revenues			$ 484,570,031.06	
Difference			$ 22,476,551.03	$ 7,379,239.05
New Revenue Stream	$27,514,672.50	$457,055,358.56	$ 484,570,031.06	$457,055,358.56
SO Discounted Rate*	7.50	0.10544		

Calculation of New Discounted Standard Offer Rate

November - April			
Discounted Revenues			$249,570,259.43
Difference			$ 11,576,198.10
New Revenue Stream	$ 27,547,912.50	$222,022,346.93	$249,570,259.43
SO Discounted Rate*	7.50	0.07648	

Difference between Standard Offer and direct access rates

May - October			
SO Rate		7.50	0.10544
Direct Access		7.50	0.04891
Difference		**0.00**	**0.05654**
Annual Generation Credit	**TOTAL $**		**$245,069,171.75**
	per kWh		**0.057**
Weighted Average	**per kWh**		**0.0469**

November - April			
SO Rate		7.50	0.07648
Direct Access		7.50	0.04390
			0.03258
	TOTAL $		**$ 94,574,458.72**
	per kWh		**0.033**

* Assume reduction flows through energy charge.

Residential Service: Year 4 (2002)

New Direct Access Rate
May - October

	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00212
Distribution			0.03837
SBC			0.00115
CTC			0.00560
	sum		0.04724

Calculation of New Discounted Standard Offer Rate
May - October

Discounted Revenues			$ 477,301,480.60	
Difference			$ 29,745,101.50	$ 7,268,550.47
New Revenue Stream	$27,514,672.50	$449,786,808.10	$ 477,301,480.60	$449,786,808.10
SO Discounted Rate*	7.50	0.10377		

Difference between Standard Offer and direct access rates
May - October

SO Rate		7.50	0.10377
Direct Access		7.50	0.04724
Difference		**0.00**	**0.056531383**
Annual Generation Credit	**TOTAL $**		**$245,039,356.72**
	per kWh		**0.057**
Weighted Average	**per kWh**		**0.0470**

November - April

	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00316
Distribution			0.03247
SBC			0.00115
CTC			0.00560
	sum		0.04238

Calculation of New Discounted Standard Offer Rate
November - April

Discounted Revenues			$245,826,705.53
Difference			$ 15,319,751.99
New Revenue Stream	$ 27,547,912.50	$218,278,793.03	$245,826,705.53
SO Discounted Rate*	7.50	0.07519	

November - April

SO Rate		7.50	0.07519
Direct Access		7.50	0.04238
		0.00	**0.03280942**
	TOTAL $		**$ 95,243,354.04**
	per kWh		**0.033**

* Assume reduction flows through energy charge.

Residential Service: Year 5 (2003)

New Direct Access Rate

May - October

	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00212
Distribution			0.03748
SBC			0.00115
CTC			0.00500
	sum		0.04575

Calculation of New Discounted Standard Offer Rate

May - October

Discounted Revenues			$ 470,141,958.39	
Difference			$ 36,904,623.71	$ 7,159,522.21
New Revenue Stream	$27,514,672.50	$442,627,285.89	$ 470,141,958.39	$442,627,285.89
SO Discounted Rate*	7.50	0.10212		

Difference between Standard Offer and direct access rates

May - October

SO Rate		7.50	0.10212
Direct Access rate		7.50	0.04575
Difference		**0.00**	**0.056369658**
Annual Generation Credit	**TOTAL $**		**$244,338,346.97**
	per kWh		**0.056**
Weighted Average	**per kWh**		**0.0470**

November - April

	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00316
Distribution			0.03172
SBC			0.00115
CTC			0.00500
	sum		0.04103

Calculation of New Discounted Standard Offer Rate

November - April

Discounted Revenues			$242,139,304.95
Difference			$ 19,007,152.57
New Revenue Stream	$ 27,547,912.50	$214,591,392.45	$242,139,304.95
SO Discounted Rate*	7.50	0.07392	

November - April

SO Rate		7.50	0.07392
Direct Access rate		7.50	0.04103
		0.00	**0.032889184**
	TOTAL $		**$ 95,474,905.07**
	per kWh		**0.033**

* Assume reduction flows through energy charge.

Residential Service: Year 6 (2004)

New Direct Access Rate

May - October	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00212
Distribution			0.03689
SBC			0.00115
CTC			0.00360
	sum		0.04376

November - April	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00316
Distribution			0.03122
SBC			0.00115
CTC			0.00360
	sum		0.03913

Calculation of Discounted Standard Offer Rate

May - October			
Revenues (no further discount from 2003)			$ 470,141,958.39
Difference			$ 36,904,623.71
New Revenue Stream	$27,514,672.50	$442,627,285.89	$ 470,141,958.39
SO Discounted Rate*	7.50	0.10212	

Calculation of Discounted Standard Offer Rate

November - April			
Revenues (no further discount from 2003)			$242,139,304.95
Difference			$ 19,007,152.57
New Revenue Stream	$ 27,547,912.50	$214,591,392.45	$242,139,304.95
SO Discounted Rate*	7.50	0.07392	

Difference between Standard Offer and direct access rates

May - October			
SO Rate		7.50	0.10212
Direct Access rate		7.50	0.04376
Difference		**0.00**	**0.058359658**
Annual Generation Credit	**TOTAL $**		**$252,964,145.48**
	per kWh		**0.058**
Weighted Average	**per kWh**		**0.0489**

November - April			
SO Rate		7.50	0.07392
Direct Access rate		7.50	0.03913
		0.00	**0.034789184**
	TOTAL $		**$100,990,466.59**
	per kWh		**0.035**

* Assume reduction flows through energy charge.

General Service: Year 1 (1999)
SUMMER

New Direct Access Rate
June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.04255			0.00115	$ 2.43	
	revenue	$ 10,388		$ 24,549			$ 663	$ -	$ 35,600
Formula 2	rate	12.50		0.04255	0.02901		0.00115	$ 2.43	
	revenue	$ 775		$ 6,532	$ 3,190		$ 303	$ -	$ 10,800
Formula 3	rate	12.50	0.721	0.04255			0.00115	$ 2.43	
	revenue	$ 263,975	$ 385,960	$ 2,805,947			$ 75,836	$ 535,314	$ 4,067,032
Formula 4	rate	12.50	0.721	0.04255	0.02901		0.00115	$ 2.43	
	revenue	$ 899,550	$ 2,322,307	$ 21,287,803	$ 18,876,888		$ 1,323,654	$ 7,826,916	$ 52,537,118
Formula 5	rate	12.50	0.721	0.04255	0.02901	0.01811	0.00115	$ 2.43	
	revenue	$ 126,050	$ 2,782,311	$ 17,482,383	$ 12,169,956	$ 17,193,200	$ 2,046,715	$ 9,377,275	$ 61,177,890
total revenues		$ 1,300,738	$ 5,490,578	$ 41,607,214	$ 31,050,034	$ 17,193,200	$ 3,447,172	$ 17,739,505	$ 117,828,441

Original Unbundled Rate
June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.11018					$ 73,956
	revenue	$ 10,388		$ 63,568					
Formula 2	rate	12.50		0.11018	0.07550				
	revenue	$ 775		$ 16,915	$ 8,302				$ 25,992
Formula 3	rate	12.50	1.85	0.11018					
	revenue	$ 263,975	$ 990,327	$ 7,265,786					$ 8,520,088
Formula 4	rate	12.50	1.85	0.11018	0.07550				
	revenue	$ 899,550	$ 5,958,763	$ 55,123,152	$ 49,128,060				$ 111,109,525
Formula 5	rate	12.50	1.85	0.11018	0.07550	0.04756			
	revenue	$ 126,050	$ 7,139,078	$ 45,269,307	$ 31,672,929	$ 45,152,324			$ 129,359,688
total revenues		$ 1,300,738	$ 14,088,168	$ 107,738,728	$ 80,809,291	$ 45,152,324			$ 249,089,249

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues		
						Discounted Revenues	$ 245,352,910		
						Difference	$ 3,736,339		
Standard Offer revenue	$ 1,300,738	$ 13,875,736	$ 106,114,164	$ 79,590,789	$ 44,471,484		$ 245,352,910	$ 245,352,910	
SO Discounted Rates	$ 12.50	$ 1.82	$ 0.10852	$ 0.07436	$ 0.04684	Original Rate less Cust charges	247,788,511	$ **0.0819**	Ave. revenue
						Percent Reduction from KW and kWh	1.508%		
						Total Reduction to Full Rate	1.500%		

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.82	$ 0.10852	$ 0.07436	$ 0.04684	0.00000	0.00000	
direct access rate	$ 12.50	$ 0.72	$ 0.04255	$ 0.02901	$ 0.01811	0.00115	$ 2.43	
Difference	**$ -**	**1.10**	**0.06597**	**0.04535**	**0.02873**	**(0.00115)**	**(2.43000)**	**TOTAL $**
Annual Generation Credit		**$ 8,385,158**	**$ 64,506,949**	**$ 48,540,755**	**$ 27,278,284**	**$ (3,447,172)**	**$ (17,739,505)**	**$ 127,524,470**
							per kWh	**$ 0.0425**

WINTER (1999)

New Direct Access Rate

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03827			0.00115	2.43	
	revenue	$ 18,763		$ 39,329			$ 1,182	$ -	$ 59,273
Formula 2	rate	12.50		0.03827	0.02600		0.00115	2.43	
	revenue	$ 1,313		$ 9,909	$ 5,115		$ 524.02	$ -	$ 16,861
Formula 3	rate	12.50	0.652	0.03827			0.00115	2.43	
	revenue	$ 573,300	$ 638,700	$ 5,056,351			$ 151,942	$ 1,300,808	$ 7,721,100
Formula 4	rate	12.50	0.652	0.03827	0.02600		0.00115	2.43	
	revenue	$ 1,080,200	$ 2,557,360	$ 23,143,821	$ 17,944,535		$ 1,489,164	$ 7,826,916	$ 54,041,996
Formula 5	rate	12.50	0.652	0.03827	0.02600	0.01614	0.00115	2.43	
	revenue	$ 124,850	$ 2,588,136	$ 16,131,447	$ 10,729,270	$ 14,964,970	$ 2,025,585	$ 9,377,275	$ 55,941,533
total revenues		$ 1,798,425	$ 5,784,196	$ 44,380,857	$ 28,678,920	$ 14,964,970	$ 3,668,397	$ 18,504,999	$ 117,780,764

Original Unbundled Rate

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	total revenues
Formula 1	rate	12.50		0.09925			
	revenue	$ 18,762.50		$ 101,995			$ 120,758
Formula 2	rate	12.50		0.09925	0.06780		
	revenue	$ 1,313		$ 25,699	$ 13,339		$ 40,350
Formula 3	rate	12.50	1.67	0.09925			
	revenue	$ 573,300	$ 1,635,934	$ 13,113,217			$ 15,322,451
Formula 4	rate	12.50	1.67	0.09925	0.06780		
	revenue	$ 1,080,200	$ 6,550,294	$ 60,021,537	$ 46,793,825		$ 114,445,857
Formula 5	rate	12.50	1.67	0.09925	0.06780	0.04252	
	revenue	$ 124,850	$ 6,629,122	$ 41,835,540	$ 27,978,634	$ 39,424,443	$ 115,992,589
total revenues		$ 1,798,425	$ 14,815,350	$ 115,097,988	$ 74,785,798	$ 39,424,443	$ 245,922,005

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 242,233,175
Difference							$ 3,688,830
New Revenue Stream	$ 1,798,425	$ 14,591,483	$ 113,358,800	$ 73,655,747	$ 38,828,720		$ 242,233,175
SO Discounted Rates	$ 12.50	$ 1.64	$ 0.09775	$ 0.06678	$ 0.04188	Original Rate less Cust charges	$ 244,123,580
						Percent Reduction from KW and kWh	1.511%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.64	$ 0.09775	$ 0.06678	$ 0.04188	0.00000	0.00	
direct access rate	$ 12.50	$ 0.65	$ 0.03827	$ 0.02600	$ 0.01614	0.00115	2.43	
Difference	**$ -**	**0.99**	**0.05948**	**0.04078**	**0.02574**	**$ (0.00115)**	**$ (2.43000)**	**TOTAL $**
Annual Generation Credit		**$ 8,807,286.02**	**$ 68,977,943.26**	**$ 44,976,827.36**	**$ 23,863,750.44**	**$ (3,668,397)**	**$ (18,504,999)**	**$ 124,452,410.87**
								per kWh
								$ 0.0390

Weighted average per kWh **0.04072**

General Service: Year 2 (2000)
SUMMER
New Direct Access Rate
June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.04075			0.00115	$ 2.20	
	revenue	$ 10,388		$ 23,511			$ 576,951	$ -	$ 610,849
Formula 2	rate	12.50		0.04075	0.02779		0.00115	$ 2.20	
	revenue	$ 775		$ 6,256	$ 3,056		$ 303	$ -	$ 10,390
Formula 3	rate	12.50	0.691	0.04075			0.00115	$ 2.20	
	revenue	$ 263,975	$ 369,901	$ 2,687,246			$ 75,836	$ 1,177,686	$ 4,574,645
Formula 4	rate	12.50	0.691	0.04075	0.02779		0.00115	$ 2.20	
	revenue	$ 899,550	$ 2,225,679	$ 20,387,261	$ 18,083,030		$ 1,323,654	$ 7,086,097	$ 50,005,271
Formula 5	rate	12.50	0.691	0.04075	0.02779	0.01735	0.00115	$ 2.20	
	revenue	$ 126,050	$ 2,666,542	$ 16,742,823	$ 11,658,155	$ 16,471,674	$ 2,046,715	$ 8,489,714	$ 58,201,673
total revenues		$ 1,300,738	$ 5,262,121	$ 39,847,097	$ 29,744,241	$ 16,471,674	$ 4,023,459	$ 16,753,497	$ 113,402,828

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

	flat	Demand	*block 1 energy*	*block 2 energy*	block 3 energy		total revenues
Discounted Revenues							$ 241,672,616
Difference							$ 3,680,294
New Revenue Stream	$ 1,300,738	$ 13,666,491	$ 104,513,968	$ 78,390,564	$ 43,800,857		$ 241,672,616
SO Discounted Rates	$ 12.50	$ 1.79	$ 0.10688	$ 0.07324	$ 0.04614	Original Rate less Cust charges	244,052,173
						Percent Reduction from KW and kWh	1.508%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.79	$ 0.10688	$ 0.07324	$ 0.04614	0.00000	0.00000	
direct access rate	$ 12.50	$ 0.691	$ 0.04075	$ 0.02779	$ 0.01735	0.00115	2.20	
Difference	**$ -**	**1.10**	**0.06613**	**0.04545**	**0.02879**	**(0.00115)**	**(2.20000)**	**TOTAL $**
Annual Generation Credit		**$ 8,404,369.74162**	**$ 64,666,871**	**$ 48,646,323**	**$ 27,329,182**	**$ (4,023,459)**	**$ (16,753,497)**	**$ 128,269,789**
								per kWh
								$ 0.0428

WINTER (2000)

New Direct Access Rate

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03666			0.00115	2.20	
	revenue	$ 18,763		$ 37,674			$ 1,182	$ -	$ 57,618
Formula 2	rate	12.50		0.03666	0.02490		0.00115	2.20	
	revenue	$ 1,313		$ 9,492	$ 4,899		$ 524.02	$ -	$ 16,228
Formula 3	rate	12.50	0.624	0.03666			0.00115	2.20	
	revenue	$ 573,300	$ 611,271	$ 4,843,633			$ 151,942	$ 2,155,122	$ 8,335,267
Formula 4	rate	12.50	0.624	0.03666	0.02490		0.00115	2.20	
	revenue	$ 1,080,200	$ 2,447,535	$ 22,170,172	$ 17,185,343		$ 1,489,164	$ 8,629,130	$ 53,001,545
Formula 5	rate	12.50	0.624	0.03666	0.02490	0.01546	0.00115	2.20	
	revenue	$ 124,850	$ 2,476,989	$ 15,452,805	$ 10,275,339	$ 14,334,475	$ 2,025,585	$ 8,732,975	$ 53,423,019
total revenues		$ 1,798,425	$ 5,535,795	$ 42,513,776	$ 27,465,581	$ 14,334,475	$ 3,668,397	$ 19,517,227	$ 114,833,677

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 238,599,677
Difference							$ 3,633,498
New Revenue Stream	$ 1,798,425	$ 14,370,973	$ 111,645,699	$ 72,542,647	$ 38,241,933		$ 238,599,677
SO Discounted Rates	$ 12.50	$ 1.62	$ 0.09627	$ 0.06577	$ 0.04124	Original Rate less Cust charges	$ 240,434,750
						Percent Reduction from KW and kWh	1.511%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.62	$ 0.09627	$ 0.06577	$ 0.04124	0.00000	0.00	
direct access rate	$ 12.50	$ 0.624	$ 0.03666	$ 0.02490	$ 0.01546	0.00115	2.20	
Difference	**$ -**	**1.00**	**0.05961**	**0.04087**	**0.02578**	**$ (0.00115)**	**$ (2.20000)**	**TOTAL $**
Annual Generation Credit		**$ 8,835,177.72**	**$ 69,131,923.32**	**$ 45,077,066.01**	**$ 23,907,457.51**	**$ (3,668,397)**	**$ (19,517,227)**	**$ 123,766,000.12**
								per kWh
								$ 0.0388

Weighted average per kWh **0.04073**

General Service: Year 3 (2001)

SUMMER

New Direct Access Rate

June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03912			0.00115	$ 1.66	
	revenue	$ 10,388		$ 22,570			$ 663	$ -	$ 33,621
Formula 2	rate	12.50		0.03912	0.02667		0.00115	$ 1.66	
	revenue	$ 775		$ 6,006	$ 2,933		$ 303	$ -	$ 10,016
Formula 3	rate	12.50	0.663	0.03912			0.00115	$ 1.66	
	revenue	$ 263,975	$ 354,912	$ 2,579,756			$ 75,836	$ 888,618	$ 4,163,097
Formula 4	rate	12.50	0.663	0.03912	0.02667		0.00115	$ 1.66	
	revenue	$ 899,550	$ 2,135,492	$ 19,571,771	$ 17,354,243		$ 1,323,654	$ 5,346,782	$ 46,631,492
Formula 5	rate	12.50	0.663	0.03912	0.02667	0.01665	0.00115	$ 1.66	
	revenue	$ 126,050	$ 2,558,491	$ 16,073,110	$ 11,188,305	$ 15,807,111	$ 2,046,715	$ 6,405,875	$ 54,205,657
total revenues		$ 1,300,738	$ 5,048,895	$ 38,253,213	$ 28,545,481	$ 15,807,111	$ 3,447,172	$ 12,641,275	$ 105,043,884

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 238,047,527
Difference							$ 3,625,089
New Revenue Stream	$ 1,300,738	$ 13,460,384	$ 102,937,775	$ 77,208,342	$ 43,140,288		$ 238,047,527
SO Discounted Rates	$ 12.50	$ 1.77	$ 0.10527	$ 0.07214	$ 0.04544	Original Rate less Cust charges	240,371,879
						Percent Reduction from KW and kWh	1.508%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.77	$ 0.10527	$ 0.07214	$ 0.04544	0.00000	0.00	
direct access rate	$ 12.50	$ 0.663	$ 0.03912	$ 0.02667	$ 0.01665	0.00115	$ 1.66	
Difference	**$ -**	**1.10**	**0.06615**	**0.04547**	**0.02879**	**(0.00115)**	**(1.66000)**	**TOTAL $**
Annual Generation Credit		**$ 8,411,489.39256**	**$ 64,684,562**	**$ 48,662,862**	**$ 27,333,177**	**$ (3,447,172)**	**$ (12,641,275)**	**$ 133,003,643**
								per kWh
								$ 0.0444

WINTER (2001)

New Direct Access Rate

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03519			0.00115	1.66	
	revenue	$ 18,763		$ 36,163			$ 1,182	$ -	$ 56,108
Formula 2	rate	12.50		0.03519	0.02390		0.00115	1.66	
	revenue	$ 1,313		$ 9,112	$ 4,702		$ 524.02	$ -	$ 15,650
Formula 3	rate	12.50	0.599	0.03519			0.00115	1.66	
	revenue	$ 573,300	$ 586,781	$ 4,649,412			$ 151,942	$ 1,626,138	$ 7,587,572
Formula 4	rate	12.50	0.599	0.03519	0.02390		0.00115	1.66	
	revenue	$ 1,080,200	$ 2,349,477	$ 21,281,188	$ 16,495,169		$ 1,489,164	$ 6,511,071	$ 49,206,269
Formula 5	rate	12.50	0.599	0.03519	0.02390	0.01484	0.00115	1.66	
	revenue	$ 124,850	$ 2,377,751	$ 14,833,175	$ 9,862,675	$ 13,759,613	$ 3,668,397	$ 6,589,426	$ 51,215,887
total revenues		$ 1,798,425	$ 5,314,009	$ 40,809,050	$ 26,362,545	$ 13,759,613	$ 5,311,209	$ 14,726,635	$ 108,081,486

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 235,020,682
Difference							$ 3,578,995
New Revenue Stream	$ 1,798,425	$ 14,153,771	$ 109,958,295	$ 71,446,243	$ 37,663,947		$ 235,020,682
SO Discounted Rates	$ 12.50	$ 1.60	$ 0.09482	$ 0.06477	$ 0.04062	Original Rate less Cust charges	$ 236,801,252
						Percent Reduction from KW and kWh	1.511%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.60	$ 0.09482	$ 0.06477	$ 0.04062	0.00000	0.00	
direct access rate	$ 12.50	$ 0.599	$ 0.03519	$ 0.02390	$ 0.01484	0.00115	1.66	
Difference	**$ -**	**1.00**	**0.05963**	**0.04087**	**0.02578**	**$ (0.00115)**	**$ (1.66000)**	**TOTAL $**
Annual Generation Credit		**$ 8,839,762.65**	**$ 69,149,245.03**	**$ 45,083,697.63**	**$ 23,904,334.54**	**$ (5,311,209)**	**$ (14,726,635)**	**$ 126,939,195.98**
								per kWh
								$ 0.0398

Weighted average per kWh **0.04201**

General Service: Year 4 (2002)
SUMMER
New Direct Access Rate
June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03763			0.00115	$ 1.46	
	revenue	$ 10,388		$ 21,711			$ 663	$ -	$ 32,762
Formula 2	rate	12.50		0.03763	0.02565		0.00115	$ 1.46	
	revenue	$ 775		$ 5,777	$ 2,820		$ 303	$ -	$ 9,675
Formula 3	rate	12.50	0.638	0.03763			0.00115	$ 1.46	
	revenue	$ 263,975	$ 341,529	$ 2,481,499			$ 75,836	$ 781,556	$ 3,944,395
Formula 4	rate	12.50	0.638	0.03763	0.02565		0.00115	$ 1.46	
	revenue	$ 899,550	$ 2,054,968	$ 18,826,322	$ 16,690,526		$ 1,323,654	$ 4,702,591	$ 44,497,612
Formula 5	rate	12.50	0.638	0.03763	0.02565	0.01602	0.00115	$ 1.46	
	revenue	$ 126,050	$ 2,462,017	$ 15,460,919	$ 10,760,406	$ 15,209,004	$ 2,046,715	$ 5,634,083	$ 51,699,193
total revenues		$ 1,300,738	$ 4,858,514	$ 36,796,227	$ 27,453,752	$ 15,209,004	$ 3,447,172	$ 11,118,230	$ 100,183,637

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 234,476,814
Difference							$ 3,570,713
New Revenue Stream	$ 1,300,738	$ 13,257,369	$ 101,385,225	$ 76,043,854	$ 42,489,629		$ 234,476,814
SO Discounted Rates	$ 12.50	$ 1.74	$ 0.10368	$ 0.07105	$ 0.04476	Original Rate less Cust charges	236,746,790
						Percent Reduction from KW and kWh	1.508%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.74	$ 0.10368	$ 0.07105	$ 0.04476	0.00000	0.00	
direct access rate	$ 12.50	$ 0.638	$ 0.03763	$ 0.02565	$ 0.01602	0.00115	$ 1.46	
Difference	**$ -**	**1.10**	**0.06605**	**0.04540**	**0.02874**	**(0.00115)**	**(1.46000)**	**TOTAL $**
Annual Generation Credit		**$ 8,398,854.96565**	**$ 64,588,997**	**$ 48,590,102**	**$ 27,280,625**	**$ (3,447,172)**	**$ (11,118,230)**	**$ 134,293,177**
								per kWh
								$ 0.0448

WINTER (2002)

New Direct Access Rate

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03385			0.00115	1.46	
	revenue	$ 18,763		$ 34,786			$ 1,182	$ -	$ 54,731
Formula 2	rate	12.50		0.03385	0.02299		0.00115	1.46	
	revenue	$ 1,313		$ 8,765	$ 4,523		$ 524.02	$ -	$ 15,124
Formula 3	rate	12.50	0.576	0.03385			0.00115	1.46	
	revenue	$ 573,300	$ 564,250	$ 4,472,367			$ 151,942	$ 1,430,217	$ 7,192,076
Formula 4	rate	12.50	0.576	0.03385	0.02299		0.00115	1.46	
	revenue	$ 1,080,200	$ 2,259,263	$ 20,470,821	$ 15,867,110		$ 1,489,164	$ 5,726,605	$ 46,893,163
Formula 5	rate	12.50	0.576	0.03385	0.02299	0.01427	0.00115	1.46	
	revenue	$ 124,850	$ 2,286,452	$ 14,268,343	$ 9,487,150	$ 13,231,110	$ 2,025,585	$ 5,795,520	$ 47,219,010
total revenues		$ 1,798,425	$ 5,109,965	$ 39,255,082	$ 25,358,783	$ 13,231,110	$ 3,668,397	$ 12,952,342	$ 101,374,104

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 231,495,372
Difference							$ 3,525,310
New Revenue Stream	$ 1,798,425	$ 13,939,828	$ 108,296,202	$ 70,366,285	$ 37,094,632		$ 231,495,372
SO Discounted Rates	$ 12.50	$ 1.57	$ 0.09338	$ 0.06379	$ 0.04001	Original Rate less Cust charges	$ 233,222,257
						Percent Reduction from KW and kWh	1.512%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy			
SO Rate	$ 12.50	$ 1.57	$ 0.09338	$ 0.06379	$ 0.04001	0.00000	0.00	
direct access rate	$ 12.50	$ 0.576	$ 0.03385	$ 0.02299	$ 0.01427	0.00115	1.46	
Difference	**$ -**	**1.00**	**0.05953**	**0.04080**	**0.02574**	**$ (0.00115)**	**$ (1.46000)**	**TOTAL $**
Annual Generation Credit		**$ 8,829,862.69**	**$ 69,041,119.74**	**$ 45,007,502.12**	**$ 23,863,521.46**	**$ (3,668,397)**	**$ (12,952,342)**	**$ 130,121,267.15**
								per kWh
								$ 0.0408

Weighted average per kWh **0.04273**

General Service: Year 5 (2003)
SUMMER

New Direct Access Rate

June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03627			0.00115	$ 1.30	
	revenue	$ 10,388		$ 20,926			$ 663	$ -	$ 31,977
Formula 2	rate	12.50		0.03627	0.02473		0.00115	$ 1.30	
	revenue	$ 775		$ 5,568	$ 2,719		$ 303	$ -	$ 9,365
Formula 3	rate	12.50	0.615	0.03627			0.00115	$ 1.30	
	revenue	$ 263,975	$ 329,217	$ 2,391,814			$ 75,836	$ 695,906	$ 3,756,748
Formula 4	rate	12.50	0.615	0.03627	0.02473		0.00115	$ 1.30	
	revenue	$ 899,550	$ 1,980,886	$ 18,145,913	$ 16,091,880		$ 1,323,654	$ 4,187,239	$ 42,629,122
Formula 5	rate	12.50	0.615	0.03627	0.02473	0.01544	0.00115	$ 1.30	
	revenue	$ 126,050	$ 2,373,261	$ 14,902,140	$ 10,374,457	$ 14,658,366	$ 2,046,715	$ 5,016,649	$ 49,497,638
total revenues		$ 1,300,738	$ 4,683,364	$ 35,466,361	$ 26,469,056	$ 14,658,366	$ 3,447,172	$ 9,899,794	$ 95,924,851

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 230,959,662
Difference							$ 3,517,152
New Revenue Stream	$ 1,300,738	$ 13,057,399	$ 99,855,963	$ 74,896,833	$ 41,848,729		$ 230,959,662
SO Discounted Rates	$ 12.50	$ 1.71	$ 0.10212	$ 0.06998	$ 0.04408	Original Rate less Cust charges	233,176,077
						Percent Reduction from KW and kWh	1.508%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.71	$ 0.10212	$ 0.06998	$ 0.04408	0.00000	0.00	
direct access rate	$ 12.50	$ 0.615	$ 0.03627	$ 0.02473	$ 0.01544	0.00115	$ 1.30	
Difference	**$ -**	**1.10**	**0.06585**	**0.04525**	**0.02864**	**(0.00115)**	**(1.30000)**	**TOTAL $**
Annual Generation Credit		**$ 8,374,035.31290**	**$ 64,389,602**	**$ 48,427,777**	**$ 27,190,363**	**$ (3,447,172)**	**$ (9,899,794)**	**$ 135,034,811**
								per kWh
								$ 0.0450

WINTER (2003)

New Direct Access Rate

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03263			0.00115	1.30	
	revenue	$ 18,763		$ 33,533			$ 1,182	$ -	$ 53,477
Formula 2	rate	12.50		0.03263	0.02216		0.00115	1.30	
	revenue	$ 1,313		$ 8,449	$ 4,360		$ 524.02	$ -	$ 14,645
Formula 3	rate	12.50	0.555	0.03263			0.00115	1.30	
	revenue	$ 573,300	$ 543,679	$ 4,311,177			$ 151,942	$ 1,273,481	$ 6,853,578
Formula 4	rate	12.50	0.555	0.03263	0.02216		0.00115	1.30	
	revenue	$ 1,080,200	$ 2,176,894	$ 19,733,025	$ 15,294,265		$ 1,489,164	$ 5,099,032	$ 44,872,580
Formula 5	rate	12.50	0.555	0.03263	0.02216	0.01376	0.00115	1.30	
	revenue	$ 124,850	$ 2,203,091	$ 13,754,092	$ 9,144,639	$ 12,758,239	$ 2,025,585	$ 5,160,394	$ 45,170,892
total revenues		$ 1,798,425	$ 4,923,664	$ 37,840,276	$ 24,443,264	$ 12,758,239	$ 3,668,397	$ 11,532,907	$ 96,965,172

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 228,022,941
Difference							$ 3,472,431
New Revenue Stream	$ 1,798,425	$ 13,729,093	$ 106,659,040	$ 69,302,527	$ 36,533,856		$ 228,022,941
SO Discounted Rates	$ 12.50	$ 1.55	$ 0.09197	$ 0.06283	$ 0.03940	Original Rate less Cust charges	$ 229,696,947
						Percent Reduction from KW and kWh	1.512%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.55	$ 0.09197	$ 0.06283	$ 0.03940	0.00	0.00	
direct access rate	$ 12.50	$ 0.555	$ 0.03263	$ 0.02216	$ 0.01376	0.00115	1.30	
Difference	**$ -**	**0.99**	**0.05934**	**0.04067**	**0.02564**	**$ (0.00115)**	**$ (1.30000)**	**TOTAL $**
Annual Generation Credit		**$ 8,805,428.94**	**$ 68,818,764.55**	**$ 44,859,263.14**	**$ 23,775,616.26**	**$ (3,668,397)**	**$ (11,532,907)**	**$ 131,057,768.76**
								per kWh
								$ 0.0411

Weighted average per kWh **0.04301**

General Service: Year 6 (2004)
SUMMER

New Direct Access Rate

June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03537			0.00115	$ 0.94	
	revenue	$ 10,388		$ 20,407			$ 663	$ -	$ 31,458
Formula 2	rate	12.50		0.03537	0.02411		0.00115	$ 0.94	
	revenue	$ 775		$ 5,430	$ 2,651		$ 303	$ -	$ 9,159
Formula 3	rate	12.50	0.600	0.03537			0.00115	$ 0.94	
	revenue	$ 263,975	$ 321,187	$ 2,332,464			$ 75,836	$ 503,193	$ 3,496,656
Formula 4	rate	12.50	0.600	0.03537	0.02411		0.00115	$ 0.94	
	revenue	$ 899,550	$ 1,932,572	$ 17,695,642	$ 15,688,444		$ 1,323,654	$ 3,027,696	$ 40,567,558
Formula 5	rate	12.50	0.600	0.03537	0.02411	0.01506	0.00115	$ 0.94	
	revenue	$ 126,050	$ 2,315,377	$ 14,532,360	$ 10,114,362	$ 14,297,603	$ 2,046,715	$ 3,627,423	$ 47,059,889
total revenues		$ 1,300,738	$ 4,569,136	$ 34,586,302	$ 25,805,457	$ 14,297,603	$ 3,447,172	$ 7,158,312	$ 91,164,720

Calculation of Standard Offer Rate (no further discount from 2003)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 230,959,662
Difference							$ -
New Revenue Stream	$ 1,300,738	$ 13,057,399	$ 99,855,963	$ 74,896,833	$ 41,848,729		$ 230,959,662
SO Rates	$ 12.50	$ 1.71	$ 0.10212	$ 0.06998	$ 0.04408	Original Rate less Cust charges	229,658,925
						Percent Reduction from KW and kWh	0.000%
						Total Reduction to Full Rate	0.000%

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.71	$ 0.10212	$ 0.06998	$ 0.04408	0.00000	0.00	
direct access rate	$ 12.50	$ 0.600	$ 0.03537	$ 0.02411	$ 0.01506	0.00115	$ 0.94	
Difference	**$ -**	**1.11**	**0.06675**	**0.04587**	**0.02902**	**(0.00115)**	**(0.94000)**	**TOTAL $**
Annual Generation Credit		**$ 8,488,263.70290**	**$ 65,269,660**	**$ 49,091,376**	**$ 27,551,126**	**$ (3,447,172)**	**$ (7,158,312)**	**$ 139,794,942**
								per kWh
								$ 0.0466

WINTER (2004)
New Direct Access Rate
November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03182			0.00115	0.94	
	revenue	$ 18,763		$ 32,700			$ 1,182	$ -	$ 52,644
Formula 2	rate	12.50		0.03182	0.02161		0.00115	0.94	
	revenue	$ 1,313		$ 8,239	$ 4,251		$ 524.02	$ -	$ 14,327
Formula 3	rate	12.50	0.541	0.03182			0.00115	0.94	
	revenue	$ 573,300	$ 529,964	$ 4,204,157			$ 151,942	$ 920,825	$ 6,380,187
Formula 4	rate	12.50	0.541	0.03182	0.02161		0.00115	0.94	
	revenue	$ 1,080,200	$ 2,121,982	$ 19,243,177	$ 14,914,669		$ 1,489,164	$ 3,686,992	$ 42,536,184
Formula 5	rate	12.50	0.541	0.03182	0.02161	0.01342	0.00115	0.94	
	revenue	$ 124,850	$ 2,147,518	$ 13,412,664	$ 8,917,674	$ 12,442,992	$ 2,025,585	$ 3,731,362	$ 42,802,645
total revenues		$ 1,798,425	$ 4,799,464	$ 36,900,937	$ 23,836,594	$ 12,442,992	$ 3,668,397	$ 8,339,179	$ 91,785,988

Calculation of Standard Offer Rate (no further discount from 2003)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 228,022,941
Difference							$ -
New Revenue Stream	$ 1,798,425	$ 13,729,093	$ 106,659,040	$ 69,302,527	$ 36,533,856		$ 228,022,941
SO Rates	$ 12.50	$ 1.55	$ 0.09197	$ 0.06283	$ 0.03940	Original Rate less Cust charges	$ 226,224,516
						Percent Reduction from KW and kWh	0.000%
						Total Reduction to Full Rate	0.000%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.55	$ 0.09197	$ 0.06283	$ 0.03940	0.00000	0.00	
direct access rate	$ 12.50	$ 0.541	$ 0.03182	$ 0.02161	$ 0.01342	0.00115	0.94	
Difference	**$ -**	**1.01**	**0.06015**	**0.04122**	**0.02598**	**$ (0.00115)**	**$ (0.94000)**	**TOTAL $**
Annual Generation Credit		**$ 8,929,629.48**	**$ 69,758,103.30**	**$ 45,465,932.60**	**$ 24,090,863.46**	**$ (3,668,397)**	**$ (8,339,179)**	**$ 136,236,952.81**
								per kWh
								$ 0.0427

Weighted average per kWh **0.04461**

APS PROPOSED SETTLEMENT

Calculation of implicit generation credits and Regulatory Asset Savings

Extra Large General Service: Year 1 (1999)

New Direct Access Delivery Rates

	flat	per kW	per kWh	Total revenue
Basic Delivery Service	2430.00			
Distribution		3.53	0.00999	
SBC			0.00115	
CTC		2.82		
Sum	2430.00	6.35	0.01114	
Revenues	$639,090.00	$ 8,497,233.45	$ 7,858,822.17	$ 16,995,145.62

Original Unbundled Rate

	flat	per kW	per kWh		Dem. Rev. to Energy
Basic Delivery Service	2430.00	11.16	0.03288		
Revenues	$639,090.00	$ 14,933,720.52	$ 23,195,518.22	$ 38,768,328.74	39.17%

Calculation of New Discounted Standard Offer Rate (Discount of 1.5%)

Discounted Revenues				$ 38,186,803.81
Difference				$ 581,524.93
New Revenue Stream	$639,090.00	$ 14,705,960.12	$ 22,841,753.70	$ 38,186,803.81
SO Discounted Rates*	2430.00	10.99	0.03238	

Difference between Standard Offer and Direct Access rates

	flat	per kW	per kWh		1999
SO Discounted Rate	2430.00	10.99	0.03238		
Direct access	2430.00	6.35	0.01114		
Difference	**0.00**	**4.64**	**0.02124**	**TOTAL $**	**per kWh**
Annual Generation Credit		**$ 6,208,726.67**	**$ 14,982,931.52**	**$ 21,191,658.19**	**0.0300**

Calculation of Average Bill Size

May - October	
Total kWh	319,405,200
Total kW	587,163
Bills	110
Avg. Bill kWh	2,903,684
Avg. Bill kW	5,338
November - April	
Total kWh	386,054,600
Total kW	750,984
Bills	153
Avg. Bill kWh	2,523,233
Avg. Bill kW	4,908
Annual	
Total kWh	705,459,800
Total kW	1,338,147
Bills	263
Avg. Bill kWh	2,682,357
Avg. Bill kW	5,088

Average transmission rate calculation

		rates
$	966,480	0.00137
$	655,692	0.49
$	1,622,172	
	0.00230	

* Assume reduction flows through demand and energy charges.

Year 2 (2000)

2000 Direct Access Delivery Rates

	flat	per kW	per kWh	
Basic Delivery Service	2430.00			
Distribution		3.33	0.00943	
SBC			0.00115	
CTC		2.55		
Sum	2430.00	5.88	0.01058	
Revenues	$639,090.00	$ 7,868,304.36	$ 7,463,764.68	$ 15,971,159.04

Percentage impact of reduction in Distribution only

1999	$11,771,202	
2000	$11,108,515	
difference	$662,687	
	1.74%	of 1999 standard offer bill
	0.0009	apparent reduction in reg. Asset charge

Calculation of New Discounted Standard Offer Rate

Discounted Revenues				$ 37,614,001.76
Difference				$ 1,154,326.99
New Revenue Stream	$639,090.00	$ 14,253,855.72	$ 22,139,531.11	$ 37,032,476.82
SO Discounted Rates*	2430.00	10.65	0.03138	

Difference between standard offer & direct access

	flat	per kW	per kWh			
SO Discounted Rate	2430.00	10.65	0.03138			
Direct Access	2430.00	5.88	0.01058		2000	
Difference	**0.00**	**4.77**	**0.02080**	**TOTAL $**	**per kWh**	
Annual Generation Credit		**$ 6,385,551.36**	**$ 14,675,766.42**	**$ 21,061,317.78**	**0.0299**	-0.62%

Year 3 (2001)

2001 Direct Access Delivery Rates

	flat	per kW	per kWh	
Basic Delivery Service	2430.00			
Distribution		3.15	0.00892	
SBC			0.00115	
CTC		1.89		
Sum	2430.00	5.04	0.01007	
Revenues	$639,090.00	$ 6,744,260.88	$ 7,103,980.19	$ 14,487,331.07

Percentage impact of reduction in Distribution only

2000	11,108,515.42	
2001	10,507,864.47	
difference	600,650.96	
	1.57%	of 1999 standard offer
	0.0009	apparent reduction in reg. Asset charge

Calculation of New Discounted Standard Offer Rate

Discounted Revenues				$ 37,143,826.73
Difference				$ 1,624,502.01
New Revenue Stream	$639,090.00	$ 14,297,467.09	$ 22,207,269.65	$ 37,143,826.73
SO Discounted Rates*	2430.00	10.68	0.03148	

Difference between standard offer and direct access rates

	flat	per kW	per kWh		
SO Discounted Rate	2430.00	10.68	0.03148		
Direct Access	2430.00	5.04	0.01007		2001
Difference	**0.00**	**5.64**	**0.02141**	**TOTAL $**	**per kWh**
Annual Generation Credit		**$ 7,553,206.21**	**$ 15,103,289.46**	**$ 22,656,495.67**	**0.0321**

* Assume reduction flows through demand and energy charges.

Year 4 (2002)

2002 Direct Access Delivery Rates

	flat	per kW	per kWh	
Basic Delivery Service	2430.00			
Distribution		2.98	0.00845	
SBC			0.00115	
CTC		1.72		
Sum	2430.00	4.7	0.0096	
Revenues	$639,090.00	$ 6,289,290.90	$ 6,772,414.08	$ 13,700,794.98

2001	10,507,864.47	
2002	9,948,813.37	
difference	559,051.10	
	1.46%	of new standard offer 1999
	0.0008	apparent reduction in reg. Asset charge

Calculation of New Discounted Standard Offer Rate

Discounted Revenues				$ 36,865,248.03
Difference				$ 1,903,080.71
New Revenue Stream	$639,090.00	$ 14,188,358.79	$ 22,037,799.25	$ 36,865,248.03
SO Discounted Rates*	2430.00	10.60	0.03124	

Difference between Standard Offer and Direct Access rates

	flat	per kW	per kWh		
SO Discounted Rate	2430.00	10.60	0.03124		
Direct access rate	2430.00	4.7	0.0096		
Difference	**0.00**	**5.90**	**0.021638916**	**TOTAL $**	**per kWh**
Annual Generation Credit		**$ 7,899,067.89**	**$ 15,265,385.17**	**$ 23,164,453.05**	**0.0328**

Year 5 (2003)

2003 Direct Access Delivery Rates

	flat	per kW	per kWh	
Basic Delivery Service	2430.00			
Distribution		2.83	0.00802	
SBC			0.00115	
CTC		1.51		
Sum	2430.00	4.34	0.00917	
Revenues	$639,090.00	$ 5,807,557.98	$ 6,469,066.37	$ 12,915,714.35

2001	2,301,612.84	
2002	9,444,743.61	
difference	(7,143,130.77)	
	-18.71%	of new standard offer 1999
	(0.0101)	apparent reduction in reg. Asset charge

Calculation of New Discounted Standard Offer Rate

Revenues (no further discount)				$ 36,865,248.03
Difference				$ 1,903,080.71
New Revenue Stream	$639,090.00	$ 14,188,358.79	$ 22,037,799.25	$ 36,865,248.03
SO Discounted Rates*	2430.00	10.60	0.03124	

Difference between Standard Offer and Direct Access rates

	flat	per kW	per kWh		
SO Discounted Rate	2430.00	10.60	0.03124		
Direct access rate	2430.00	4.34	0.00917		
Difference	**0.00**	**6.26**	**0.022068916**	**TOTAL $**	**per kWh**
Annual Generation Credit		**$ 8,380,800.81**	**$ 15,568,732.88**	**$ 23,949,533.69**	**0.0339**

* Assume reduction flows through demand and energy charges.

Year 6 (2004)

2003 Direct Access Delivery Rates

	flat	per kW	per kWh	
Basic Delivery Service	2430.00			
Distribution		2.73	0.00774	
SBC			0.00115	
CTC		1.09		
Sum	2430.00	3.82	0.00889	
Revenues	$639,090.00	$ 5,111,721.54	$ 6,271,537.62	$ 12,022,349.16

Calculation of New Discounted Standard Offer Rate

Revenues (no further discount)				$ 36,865,248.03
Difference				$ 1,903,080.71
New Revenue Stream	$639,090.00	$ 14,188,358.79	$ 22,037,799.25	$ 36,865,248.03
SO Discounted Rates*	2430.00	10.60	0.03124	

Difference between Standard Offer and Direct Access rates

	flat	per kW	per kWh		
SO Discounted Rate	2430.00	10.60	0.03124		
Direct access rate	2430.00	3.82	0.00889		
Difference	**0.00**	**6.78**	**0.022348916**	**TOTAL $**	**per kWh**
Annual Generation Credit		**$ 9,076,637.25**	**$ 15,766,261.62**	**$ 24,842,898.87**	**0.0352**

* Assume reduction flows through demand and energy charges.

CALCULATION OF RELEVANT WHOLESALE MARKET PRICES

There is a "day ahead" spot market in California, that indicates the spot price of energy for every hour in the last year and more. This reflects price bids from generators for the next day and bids to purchase for the next day from buyers. The California market reports the spot price for the Palo Verde zone, which is where power is bought and sold for Arizona. This market is still "thin", meaning that the volume of trades is not very large, but it is the best indicator we have of wholesale trades. There will also be bilateral sales and purchases, but the terms and prices of these trades are seldom public information.

Spot hourly prices vary a great deal - a typical summer midday price will be a multiple of a winter evening price. We weighted the Palo Verde price by the California Power Exchange hourly load, which is available electronically. We rejected results for June of 1998. This was only the third month in which trading had been occurring, and the unweighted average price was so low compared to preceding and all succeeding months as to be viewed as an anomaly. The average weighted price for the last eleven months was 28.06 cents. However, Arizona load varies more seasonally than does California. In addition, the 1998 summer was milder than normal, which will tend to reduce average prices and also peak loads. We increased the California load weighted price to 2.9 cents per kWh to account for these factors. If wholesale prices are weighted for each customer group, to reflect different use patterns, we would expect that Extra-Large General Service would be somewhat lower than the average Arizona value, while General Service and Residential weighted wholesale prices would be higher than the average.

To get power to the customer will also require accounting for line losses, which increases the price from 5 percent to 7 percent, depending on the customer's voltage level, or 1.4 mills for Extra-Large General Service customers. In addition, the supplier will be required to acquire ancillary services. Initially, all suppliers may buy all of these services from APS. Based on APS' Open Access Transmission Tariff, the cost of these required services is about .1 cent per kWh.

Finally, and most significantly, the Direct Access Rates do not provide for transmission to the customer. APS will charge separately for this essential part of service. Mr. Higgins states that he has seen the rates that APS will charge; the Commission and customers have not. I have used the unbundled transmission costs by class based on APS' unbundled rates in the November Settlement rates, which ranged from 2 to 4 mills per kWh. The minimum cost[1] for a retail customer to have purchased all energy needs from the California spot market, with minimum transmission costs and paying APS only for ancillary services, would be at least 3.2 cents per kWh for the Extra-Large General Service class.

[1] There are no transmission charges other than from APS in this price.

ESTIMATION OF RETAIL GENERATION PRICE

First, customers, or their suppliers, will not project their load exactly, which means they will have to pay APS for "load balancing" i.e. when they have ordered slightly less or more energy than their actual load, they have to pay for the difference between their projected load and their actual load. This service will probably cost about 1 mill on average. Second, there is risk to the customer from purchasing from the spot market. If a supplier must quote a price to customers, the supplier will take the risk and must charge for it. If the customer is willing to take the risk, there is still a value that the customer will place on that risk. If the customer absolutely knew that the Company would charge 3 cents for the next year, and only expected that the market price would be 3 cents for the same period, the wise customer would choose the Company supply to eliminate this risk. Third, the supplier has costs associated with customer contact, and estimating the customer load. The Company includes these costs in its distribution costs and does not have to charge for them, but a supplier will. Fourth, a supplier will need to make some profit. If the supplier sells the product at exactly what he paid for it, he won't stay in existence very long. The Company makes a profit when it sells generation, but this profit is reflected in a return on its generating plants. Below I present a conservative estimate that builds a minimum retail price from the wholesale price of these costs.

ESTIMATE OF RETAIL MARKET PRICE

	Residential	General Service	Extra Large GS
Price of predicted load			
Spot wholesale price	3.10	3.00	2.70
Line loss factor	7.00%	7.00%	5.00%
Cost of line losses	0.22	0.21	0.14
Transmission cost	0.40	0.34	0.20
Cost of ancillary ser vices	0.10	0.10	0.10
Cost at customer level	3.82	3.65	3.14
Additional retail costs			
Balancing load & energy	0.15	0.12	0.10
Marketer costs	0.60	0.40	0.15
Retail price	4.57	4.17	3.39